UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _______**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-025-1
(GENERATOR RELAY LOADABILITY)

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
William H. Edwards
Counsel
Brady A. Walker
Associate Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net
brady.walker@nerc.net

Counsel for the North American Electric Reliability Corporation

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard PRC-025-1 – Generator Relay Loadability for Commission approval. NERC requests that the Commission approve proposed Reliability Standard PRC-025-1 (**Exhibit A**) and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**) and Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") (included in **Exhibit A** and explained in **Exhibit E**). Proposed PRC-025-1 was developed to respond to Commission directives in Order No. 733[5] to address generator protective relay loadability.

[1] 16 U.S.C. § 824o (2006).

[2] 18 C.F.R. § 39.5 (2013).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[4] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

[5] *Transmission Relay Loadability Standard*, Order No. 733, 130 FERC ¶ 61,221, at P 104-08 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127, *order on reh'g and clarification*, Order No. 733-B, 136 FERC ¶ 61,185 (2011).

NERC submits proposed Reliability Standard PRC-025-1 to meet the Commission's September 30, 2013 deadline[6] to develop a new generator relay loadability Reliability Standard; however, NERC requests the Commission delay its approval of proposed Reliability Standard PRC-025-1 until proposed Reliability Standard PRC-023-3 – Transmission Relay Loadability is submitted to the Commission as a supplement to this petition. Proposed PRC-023-3 will be presented to the Board for approval in November 2013 and filed with the Commission by the end of the year. During the development of proposed Reliability Standard PRC-025-1, clarifying changes to PRC-023-2 were identified by the standard drafting team as necessary to establish a bright-line between the applicability of load-responsive protective relays in the transmission and generator relay loadability Reliability Standards. As a result, a supplemental Standard Authorization Request was approved by the Standards Committee at its January 16-17, 2013 meeting to authorize the standard drafting team to make the corresponding changes. NERC requests the Commission take concurrent action on the proposed Reliability Standards PRC-025-1 and PRC-023-3 to preserve consistency between proposed Reliability Standards PRC-025 and PRC-023.

As required by Section 39.5(a)[7] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard PRC-025-1, a summary of the development history (**Exhibit F**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[8] (**Exhibit C**). Proposed

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6 NERC was granted a one-year extension of time until September 30, 2013 to develop a new generator relay loadability standard. *See Notice of Extension of Time*, Docket No. RM08-13-001 (issued Feb. 15, 2012).

7 18 C.F.R. § 39.5(a) (2013).

8 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Reliability Standard PRC-025-1 was approved by the NERC Board of Trustees on August 15, 2013.[9]

I. EXECUTIVE SUMMARY

Proposed Reliability Standard PRC-025-1 addresses generator Facilities protective relay loadability. The proposed Reliability Standard is designed to prevent generator tripping when conditions do not pose a direct risk to the generator and associated equipment and will reduce the risk of unnecessary generator tripping—events that increase the severity of disturbances.

Proposed PRC-025-1 requires Generator Owners, Transmission Owners, and Distribution Providers to apply an appropriate setting for load-responsive relays based on calculations or simulations for conditions established in Attachment 1 of the proposed Reliability Standard. The Attachment 1 criteria are representative of the short-term conditions during which generation Facilities have, in the past, disconnected when otherwise capable of providing Reactive Power resources. By minimizing these risks, proposed Reliability Standard PRC-025-1 serves the important reliability goal of limiting the risk for severe power system disturbances.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[10]

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[9] *See NERC Board of Trustees Agenda Item 7b, available at* http://www.nerc.com/gov/bot/BOT%20May%209%202013%20%20Boston%20MA/7b-Board%20Write-up%20Phase%202%20Relay%20Loadability%20Generation%20-%20PRC-025-1.pdf.

[10] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
William H. Edwards*
Counsel
Brady A. Walker*
Associate Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net
brady.walker@nerc.net

Mark G. Lauby*
Vice President and Director of Standards
Howard Gugel*
Director of Standards Development
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
mark.lauby@nerc.net
howard.gugel@nerc.net

III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[12] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[13] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[14] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become

[11] 16 U.S.C. § 824o (2006).
[12] *Id.* § 824(b)(1).
[13] *Id.* § 824o(d)(5).
[14] 18 C.F.R. § 39.5(a) (2013).

mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[15] and Section 39.5(c)[16] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[17] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[18] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and

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15 16 U.S.C. § 824o(d)(2).

16 18 C.F.R. § 39.5(c)(1).

17 Order No. 672 at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

18 The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of Project 2010-13 Relay Loadability

a) PRC-023-1 — Transmission Relay Loadability

NERC developed Reliability Standard PRC-023-1 to address key August 14, 2003 blackout[19] recommendations regarding relay loadability issues. Relay loadability issues were found to have played a pivotal role in accelerating and spreading the early part of the cascading outage in Ohio and Michigan during the blackout. Relay loadability refers to the ability of protective relays to restrain operation for load conditions. As protective relays can respond only to measured voltage and current, they must be set such that they will detect the faults for which they must operate while avoiding unnecessary operation under non-fault load conditions.

The currently-effective PRC-023-1 Reliability Standard required certain Transmission Owners, Generator Owners and Distribution Providers to set protective relays to maintain reliable protection for all fault conditions while meeting specified criteria to ensure settings do not contribute to cascading outages.

Reliability Standard PRC-023-1 specifically addresses Recommendation 8A[20] approved by the NERC Board of Trustees in February 2004, and the U.S.-Canada Power System Outage

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[19] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 80 (2004) ("2003 Blackout Report").

[20] NERC, *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts*, at 13 (Feb. 10, 2004). Recommendation 8a of the NERC Blackout Report provides:

> All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004, submit justification to NERC for applying zone 3 relays outside of these

Task Force's Recommendation 21A,[21] "Make More Effective and Wider Use of System Protection Measures," as included in the 2003 Blackout Report.

The Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to approve Reliability Standard PRC-023-1 on May 21, 2009.[22] The Commission approved Reliability Standard PRC-023-1 in Order No. 733. Also in the Final Rule, the Commission directed NERC to: (1) make certain modifications to the approved Reliability Standard PRC-023-1; (2) submit a timeline for NERC's development of a new Reliability Standard to address generator protective relay loadability; and (3) develop a new Reliability Standard addressing the issue of protective relay operation due to power swings.[23]

b) Project 2010-13

To respond to the directives in Order No. 733, NERC proposed to address the Commission's directives in three phases in Project 2010-13. Phase I focused on making specific modifications[24] to Reliability Standard PRC-023-1 identified in Order No. 733. Phase I was completed and the revised Reliability Standard PRC-023-2[25] became mandatory on July 1, 2012. Phase II has focused on developing a new Reliability Standard to address generator relay loadability as proposed in this petition. Phase III will focus on developing requirements that address relay operations due to power swings. Phase III is currently under development and is tentatively scheduled to be completed by December 2014. The NERC Planning Committee, on

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recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

[21] 2003 Blackout Report at 156-59.

[22] *Transmission Relay Loadability Standard*, Notice of Proposed Rulemaking, 127 FERC ¶ 61,175 (2009).

[23] Order No. 733 at P 104-P 108.

[24] *Id.* at P 47.

[25] *Transmission Relay Loadability* Standard, Order No. 759, 138 FERC ¶ 61,197 (2012) ("Order No. 759").

August 19, 2013, approved a System Protection and Control Subcommittee report[26], developed with support from the System Analysis and Modeling Subcommittee, intended to inform the development process.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in **Exhibit C**, proposed Reliability Standard PRC-025-1 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The reliability benefits of proposed Reliability Standard PRC-025-1 are discussed below along with an explanation of how the proposed Reliability Standard satisfies the Commission's directives related to generator relay loadability in Order 733. Also included is a detailed explanation of the content of Reliability Standard PRC-025-1 and associated changes in proposed Reliability Standard PRC-023-3, which is currently in formal development.

A. Reliability Benefits and Technical Explanation of Proposed Reliability Standard PRC-025-1

Analyses of power system disturbances over the last twenty-five years have found generators to have tripped unnecessarily—an occurrence that has the potential to extend the scope and duration of a disturbance. During the recovery phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, wherein system voltage is widely depressed. In order to support the system during this phase of a disturbance, proposed Reliability Standard PRC-025-1 establishes criteria for setting load-responsive relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods. Premature or unnecessary tripping of generators during this period can

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[26] *Protection System Response to Power Swings*, NERC System Protection and Control Subcommittee, .approved by the NERC Planning Committee on August 19, 2013.

increase the severity of the voltage disturbance making it essential to assure this dynamic capability is available to support system recovery.

Proposed Reliability Standard PRC-025-1 establishes a risk-based Requirement in which the Generator Owner, Transmission Owner, or Distribution Provider that applies load-responsive relays must identify the type of protective relay and its application, and apply an appropriate setting based on its calculations or simulations of conditions established in Attachment 1 to proposed Reliability Standard PRC-025-1.

NERC's proposed Reliability Standard PRC-025-1 addresses the issue of generator relay loadability by establishing a new Reliability Standard for load-responsive protective relays applied on generating Facilities for the conditions, namely depressed voltages, observed during the August 2003 blackout. Proposed Reliability Standard PRC-025-1 includes criteria for load-responsive protective relays on generator step-up ("GSU") transformers and on unit auxiliary transformers ("UAT") that supply station service power to support the on-line operation of generating units or generating plants. These transformers are referred to as station power, UATs, or station service transformer(s) and are used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in the removal of the generator from service.

The *Guidelines and Technical Justification* can be found in the Application Guidelines section the proposed Reliability Standard (**Exhibit A**). The document provides analysis of protective functions and generator performance addressed within this Reliability Standard. The relay setting criteria are based on the system conditions observed during the August 2003 Blackout. The criteria for relays applied on synchronous generators, GSU transformers, and Elements that connect the GSU transformer(s) to the Transmission system are based on the response of the synchronous generator to depressed Transmission System voltage. Under this condition the generator will respond by increasing its Reactive Power output to support its terminal voltage – a response known as field-forcing. The criteria for relays applied on these Elements are similar because relays applied on each of these Elements are challenged by the loadability condition resulting from the increased generator output. An allowance is made for relays applied on the transmission side of the GSU transformer to account for Reactive Power losses in the transformer.

The criteria for relays applied on asynchronous generators, their GSU transformers, and Elements that connect the GSU transformer(s) to the Transmission system are based on the response of the asynchronous generator to depressed Transmission System voltage. Asynchronous generators do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. However, asynchronous generators will support the system during a disturbance and the criteria account for the generator response and any static or dynamic Reactive Power devices that contribute to the power flow. The criteria for relays applied on these Elements are the same because relays applied on each of these Elements are challenged by the loadability condition resulting from the increased generator output. An allowance is not made for relays applied on the transmission side of the GSU transformer because the Reactive Power losses are not significant for asynchronous generators.

The criteria for relays applied on UAT transformers are based on the increased current requirements of station service load during a depressed voltage condition. In this the case the current is based on the generator terminal voltage associated with a depressed system voltage. A conservative allowance is provided to avoid complex calculations for this load condition. As an alternative, entities may base the setting on actual current measured when the generator is operating at its maximum gross output.

Generator Owners, Transmission Owners, and Distribution Providers may at times find the relay setting criteria are in conflict with their desired protection goals. In such cases, it is suggested that entities consider the requirement within this Reliability Standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

B. Commission Directives Addressed

Proposed Reliability Standard PRC-025-1 addresses and meets the Commission's directives in Order No. 733 related to generator relay loadability as outlined below.

a) Proposed Reliability Standard PRC-025-1 is aligned with the Requirements and expected outcome of PRC-023-1

The Commission declined to adopt its NOPR proposal to require the previously approved Reliability Standard PRC-023-1 to address issues of generator step-up and auxiliary transformer loadability.[27] The Commission stated that "it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcome of PRC-023-1."[28] In Order No. 733, the Commission also stated:

> We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability

[27] *Id.* at P 104.
[28] *Id.*

> Standard if it is not to be addressed with transmission relay loadability.[29]

During the development of proposed Reliability Standard PRC-025-1, the standard drafting team and industry stakeholders identified potential compliance overlap and reliability gaps between Reliability Standard PRC-023-2 and proposed Reliability Standard PRC-025-1. Reliability Standard PRC-023-2 and proposed Reliability Standard PRC-025-1 overlap with regard to the application of load-responsive protective relays on transmission lines that connect the generating plant or generating units to the Transmission System. Proposed Reliability Standard PRC-025-1 introduced criteria for relays applied at the terminals of these lines. At the same time Requirement R1, Criterion 6 of Reliability Standard PRC-023-2 requires entities to "set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of aggregated generation nameplate capability." The compliance overlap would result in a finding of a non-compliance with both Reliability Standards—generation and transmission—unless revisions are made to avoid overlap—two sets of Requirements applying to the same relay—between the two Reliability Standards.

Coordinating changes to Reliability Standard PRC-023-2 are necessary to properly align proposed Reliability Standard PRC-025-1 with Reliability Standard PRC-023-2. First, Requirement R1, Criterion 6 of PRC-023-2 was removed and the applicability section of PRC-023-2 was revised to exclude "Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a Bulk Electric System generating unit or generating plant." These changes avoid overlap with the requirements in PRC-025-1 that apply to these Facilities.

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[29] *Id.* at P 106.

Second, PRC-025-1 was developed to include relay loadability requirements for all load responsive protective relays applied at the terminals of generators and GSU transformers. Corresponding modifications are being developed to revise the applicability of PRC-023-3 and to remove section 2.4 of Attachment A to avoid overlap or gaps between the two proposed Reliability Standards. The applicability sections for the two proposed Reliability Standards are based on the location where the relays are applied and are independent of the intended protection function.

The proposed applicability for PRC-025-1 includes that all relays that may operate in response to increased generator output during stressed system conditions, assuring that these relays are addressed in one Reliability Standard. The loadability challenge presented to relays applied at the terminals of generators and GSU transformers is different than the transmission relay loadability conditions observed during the August 2003 Blackout. The transmission relay loadability requirements are based on assuring relays do not operate unnecessarily to trip transmission elements during conditions of depressed transmission system voltage (0.85 per unit) and high transmission power factor angle (30 degrees). Since the objective is to keep transmission Elements in service when the Elements are not at risk of thermal overloading, the setting requirements are based on the Facility Rating. Similarly, the generator relay loadability requirements ensure relays do not operate unnecessarily to trip generating units during depressed Transmission System voltage. However, the voltage and power factor conditions that challenge relays applied at the terminals of generators and GSU transformers are significantly different. The voltage and power factor angle will be higher, particularly for synchronous generators, due to the increased Reactive Power output from the generator to support voltage at its terminals. For example, generator terminal voltage may approach 0.95 per unit during depressed transmission system voltage and the power factor angle may approach 60 degrees. The generator relay loadability requirements, therefore, are based on the generator capability rather than the Facility Rating of the generator or GSU transformer.

The protective relays applied at the terminals of generators and GSU transformers will be challenged by the increased generator output during stressed system conditions regardless of the intended protection function; *e.g.*, whether they are applied to protect the generator or GSU transformer, or to provide backup protection for the Transmission System. Thus, to prevent unnecessary tripping of the generator, the relay loadability requirements for these relays must be independent of the intended protection function.

The applicability requirements in PRC-025-1 and corresponding applicability proposed in PRC-023-3 address the Commission's concern that all generator and GSU transformer load-responsive protective relays are subject to appropriate requirements in a Reliability Standard. Basing applicability on the physical location where the relay is applied provides the following advantages:

(i) Facilitates establishing generator relay loadability requirements based on the physics associated with increased generator output during stressed system conditions.

(ii) Avoids ambiguity whether the intended protection function is for the generating unit or the Transmission System. For example, a relay may be applied at the terminals of a generator to provide backup protection for the GSU transformer, but because the relay setting must "over-reach" the GSU transformer terminals the relay inherently provides backup protection for the high-voltage bus and close-in portions of transmission lines.

(iii) Provides clear division of applicability between the generator and transmission relay loadability Reliability Standards based on the physical location, independent of the entity that owns the relay.

b) Proposed Reliability Standard PRC-025-1 is Timely

In Order No. 733, the Commission directed "the ERO to submit to the Commission an updated and specific timeline to explain when it expects to develop and submit this proposed Standard." Further, the Commission stated it "will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner."[30] NERC submitted a specific timeline to the Commission. The Commission granted a one-year extension of time to develop Reliability Standard for generator relay loadability on February 15, 2012, allowing NERC until September 30, 2013 to complete the Reliability Standard pursuant to Order No. 733.[31] With this petition, NERC has timely submitted the proposed Reliability Standard.

c) Consideration of a Generic Rating Percentage for Generator Step-up Transformers

In Order No. 733, the Commission encouraged NERC to "consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage."[32] Proposed Reliability Standard PRC-025-1 establishes a Requirement that each Generator Owner, Transmission Owner, and Distribution Provider to apply settings on its load-responsive protective relays for GSU transformers.

For relays applied on the generator side of GSU transformers connected to synchronous generator units, the proposed Reliability Standard establishes settings based on 100 percent of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to

[30] *Id.* at P 103.

[31] *See Transmission Relay Loadability Reliability Standard*, Notice of Extension of Time Docket, No. RM08-13-001 (Feb. 15, 2012).

[32] Order No. 733 at P 108.

the Transmission Planner, and Reactive Power capability, in megavoltampere-reactive (Mvar), equal to 150 percent of the MW value derived from the generator nameplate megavoltampere (MVA) rating at rated power factor. A similar generic criterion is established for relays applied at the high-side of GSU transformers connected to synchronous generators,

For relays applied at the generator side of GSU transformers connected to asynchronous generator units, the proposed Reliability Standard establishes settings based on 130 percent of the generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the aggregated generators at rated power factor. Asynchronous generator criteria also include inverter-based installations. A similar generic criterion is established for relays applied at the high-side of GSU transformers connected to asynchronous generators,

While these generic criteria achieve the goal of simplifying the calculations necessary to establish relay settings, these generic criteria are conservative to assure they provide adequate relay loadability for all applications. In some cases these generic criteria may be overly conservative due to limitations of the generating unit. To address such cases, proposed Reliability Standard PRC-025-1 provides multiple options for most applications, allowing entities to use simpler calculations yielding more restrictive settings, more complex calculations yielding less restrictive settings, or based on the modeled output of the generating plant or generating unit.

C. Requirement in Proposed Reliability Standard PRC-025-1

Proposed Reliability Standard PRC-025-1 establishes one Requirement for relay settings on each load-responsive protective relay. The Requirement is as follows:[33]

[33] A full technical justification is included in **Exhibit A**.

> R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High][Time Horizon: Long-Term Planning]*.

Requirement R1 is risk-based. For ease of use, a table providing the relevant criteria was developed including application, relay type, voltage to consider, and the pickup setting. The criteria table is listed in Attachment 1 of proposed Reliability Standard PRC-025-1. Based on the criteria table, an entity must set its load-responsive relay to the appropriate setting based on the entity's calculation or simulation for the specified conditions. Each responsible entity must be aware of each protective relay subject to the proposed Reliability Standard and set the relay using an appropriate option established in the criteria table. The proposed Reliability Standard furthers reliability by establishing setting criteria to prevent operation for short-term conditions during which generation Facilities are capable of providing the system with increased Reactive Power. It is under these circumstances that generation Facilities have historically been disconnected. In previous disturbance events, the disconnecting of generation Facilities has increased the severity of the event.

The basis for the proposed Reliability Standard's loadability criteria for relays applied at the terminals of synchronous generators or low-side of the GSU transformer are the dynamic generating unit loading values observed during the August 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the System Protection and Control

Subcommittee technical reference document[34], two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing); and (2) when the unit is operating at its declared low active Real Power operating limit (*e.g.*, 40 percent of rated Real Power, with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing)).

Both conditions above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which is based on these observations. However, the drafting team evaluated the benefit of defining two operating points and determined, for the purposes of this proposed Reliability Standard, that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the Reliability Standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. In addition, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a Bulk Electric System generating unit or generating plant.

[34] *Technical Reference Document: Power Plant and Transmission System Protection Coordination – Revision 1*, NERC System Protection and Control Subcommittee (Jul. 2010), available at http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf. The technical reference document was approved by the NERC Planning Committee on July 30, 2010.

The basis for the proposed Reliability Standard's loadability criteria for relays applied at the terminals of asynchronous generators or low-side of the GSU transformer is the expected dynamic generating unit loading for the same system conditions used for synchronous generators. Asynchronous generators do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. However, asynchronous generators will support the system during a disturbance.

The generator output used to determine settings is derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This calculation approximates the stressed system conditions.

Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio and the setting basis is the same for relays on either side of the GSU transformer, and for relays applied on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a Bulk Electric System generating unit or generating plant.

The basis for the proposed Reliability Standard's loadability criteria for relays applied on UATs is based on the expected performance of station service load during depressed system voltage. The performance of the UAT loads during stressed system conditions is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the proposed Reliability Standard elected to increase the margin to 150 percent from that used elsewhere in this proposed Reliability Standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91[35] at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions.

Because of the various design and loading characteristics of UATs, two options are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this proposed Reliability Standard. These options are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT. For the first option, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions. For the second option, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting pickup compared to the first option. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load

[35] IEEE Guide for Protecting Power Transformers, *IEEE Std C37.91-2008 (Revision of IEEE Std C37.91-2000)* (2008).

placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

D. Enforceability of PRC-025-1

The proposed Reliability Standard PRC-025-1 contains a Measure that supports the Requirement by clearly identifying acceptable evidence of compliance and how the Requirement will be enforced. The Implementation Plan also discusses the documentation necessary to comply with the proposed Reliability Standard. The VSL provides further guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRF and VSL for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The VSL has been developed based on the situations an auditor may encounter during a compliance audit. For a detailed review of the VRF, VSL, and the analysis of how the VRF and VSL were developed using these guidelines, see **Exhibit E**.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standard, the VRF and VSL (explained in **Exhibit E**), and other associated elements included in **Exhibit A**; and
- approve the implementation plan included in **Exhibit B**.

Respectfully submitted,

/s/ Brady A. Walker

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
William H. Edwards
Counsel
Brady A. Walker
Associate Counsel
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net
brady.walker@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: September 30, 2013

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.
7. Draft 3 of the standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013 and a successive ballot in the last ten days of the comment period.
8. Draft 4 of the standard was posted for a 30-day formal comment period from June 20 to July 19, 2013 and a successive ballot in the last ten days of the comment period.
9. Draft 5 of the standard was posted for a 10-day recirculation ballot from August 2 to August 12, 2013.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 5 of PRC-025-1, Generator Relay Loadability for a 10-day recirculation.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and Initial Ballot	January 2013
30-day Formal Comment Period and Successive Ballot	May 2013
30-day Formal Comment Period and Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013

File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations,

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of fullload current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[4]	**Pickup Setting Criteria**
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues with a different relay type below			
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[4]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="6">Generator step-up transformer(s) connected to synchronous generators</td><td rowspan="5">Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer
If the relay is installed on the high-side of the GSU transformer use Option 14</td><td>7a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[4]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="5">Generator step-up transformer(s) connected to synchronous generators</td><td rowspan="5">Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer
If the relay is installed on the high-side of the GSU transformer use Option 16</td><td>9a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>9b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>9c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="5">A different application starts on the next page</td></tr>
</table>

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[4]	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 7	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 9	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 10	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 11	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[5]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power megawatt (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in megavoltampere-reactive (Mvar) which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer(s) and on Elements that connect the GSU transformer(s) to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

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[5] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of PRC-025-1 – Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria (“Table 1”) in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner’s interconnection facility (in some cases labeled a “transmission Facility” or “generator leads”) consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term “generator interconnection Facility” consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility generally implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as “Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.” to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

This standard is applicable to Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. Elements may also supply generating plant loads. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

In this particular case, the applicable responsible entity’s directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.

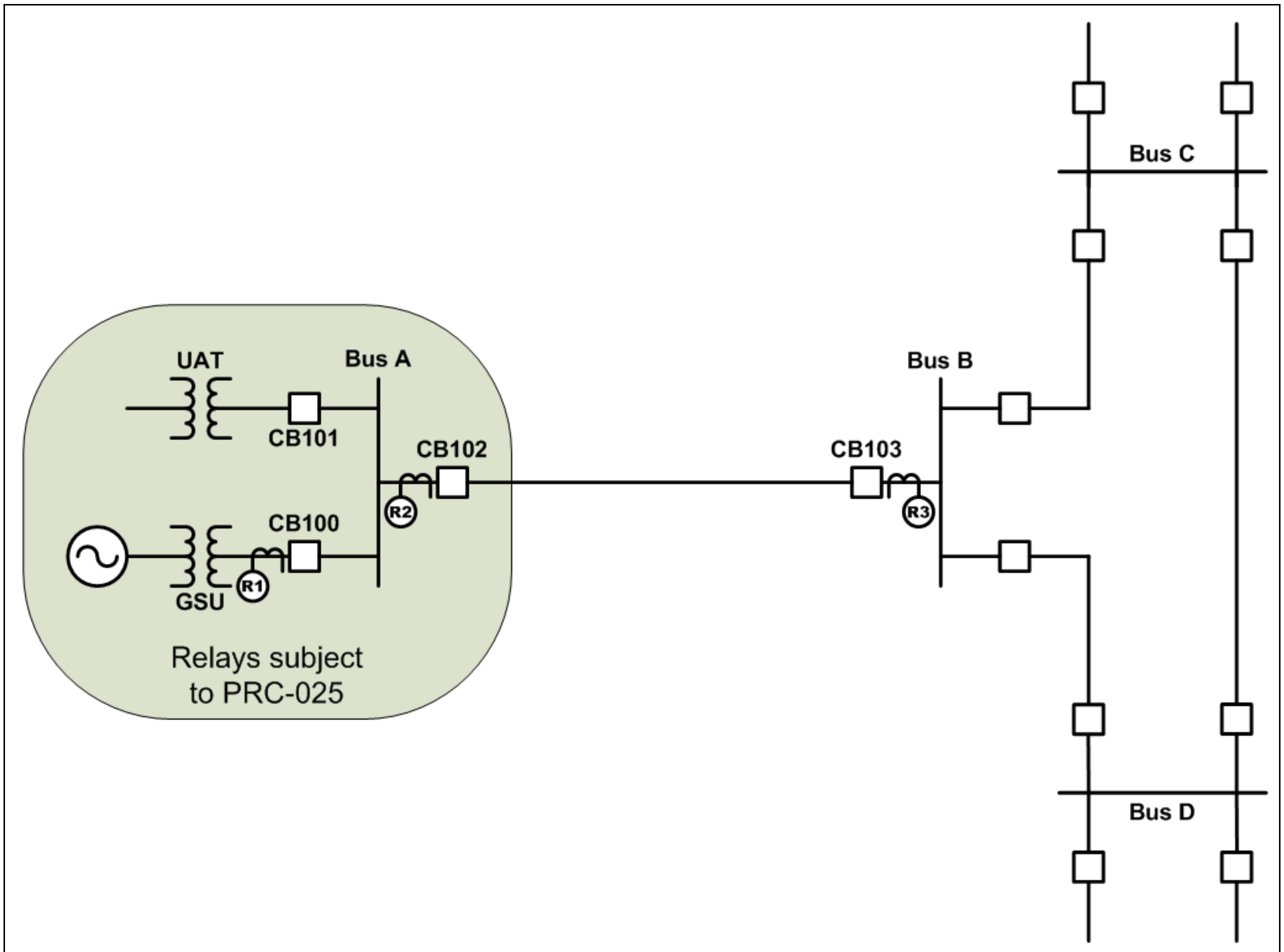


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. Elements may also supply generating plant loads. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.

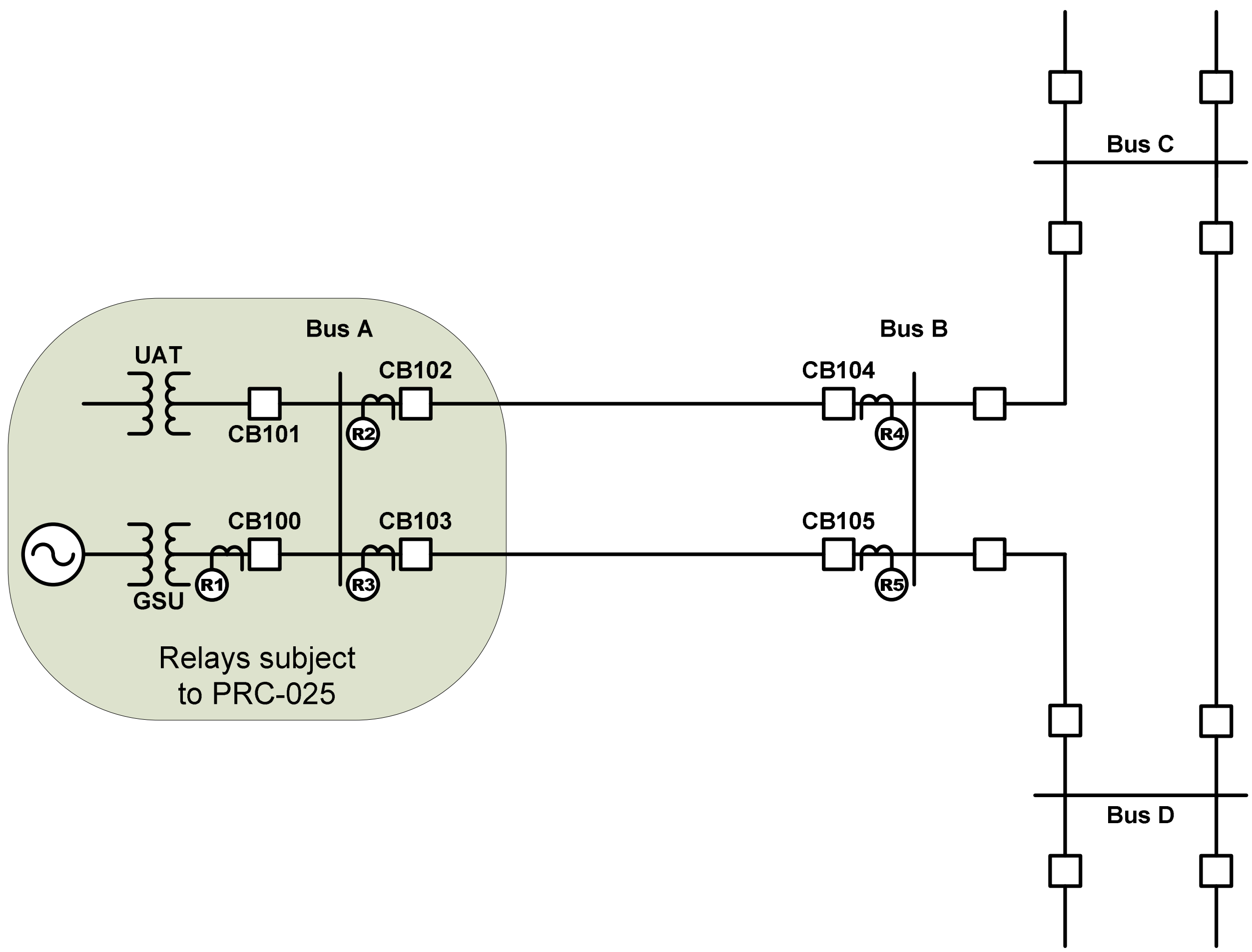


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity’s loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

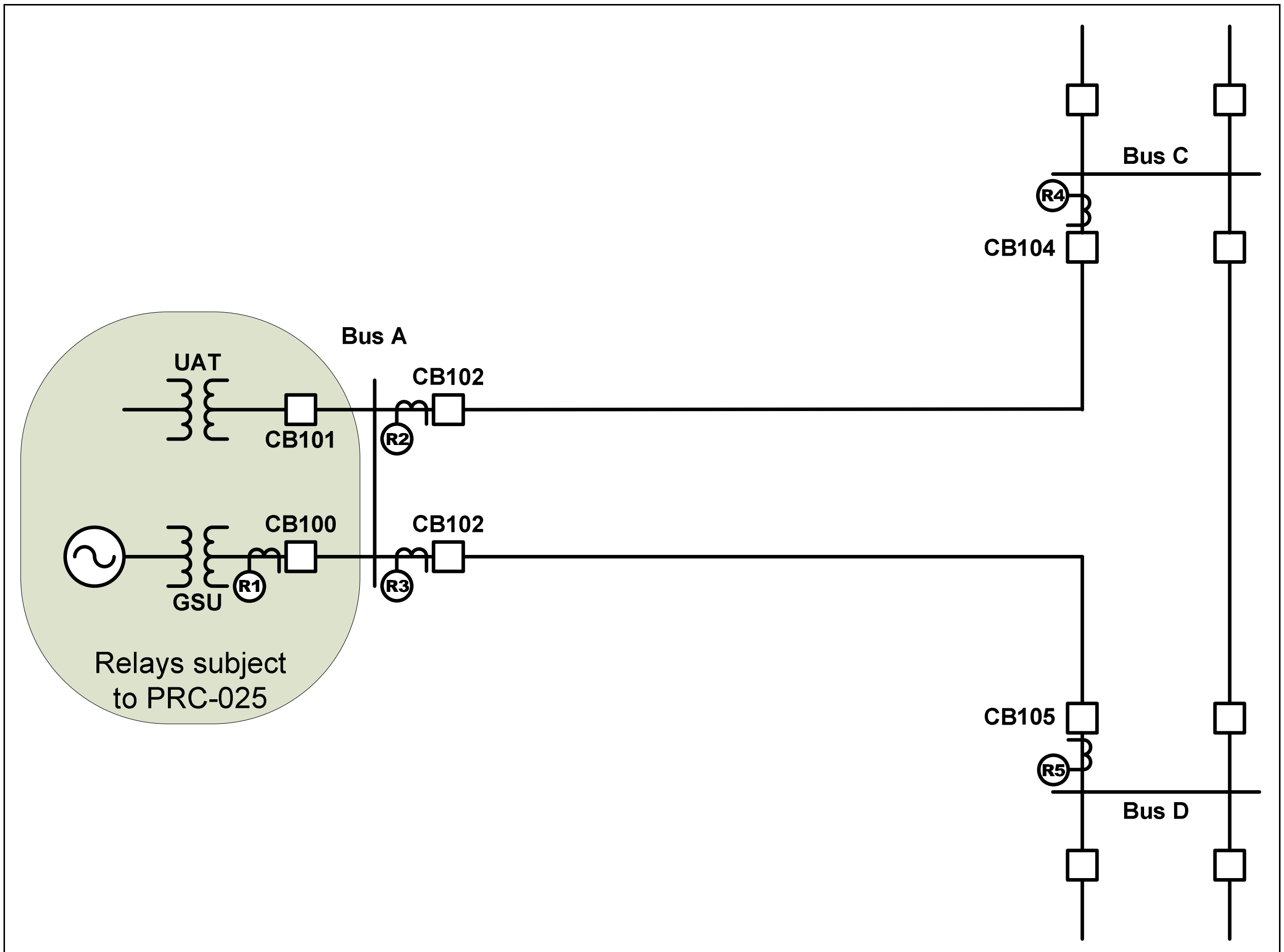


Figure 3. Generation exported through a network.

This standard is also applicable to the UAT(s) that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column "Pickup Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective elements associated with the facility are included in PRC-025.

Individual dispersed power producing resources that comprise an aggregated facility will behave similarly for the system conditions described in the Introduction above and addressed within this standard. Therefore, it is necessary to apply the criteria to each individual power producing resource.

The Elements utilized in the aggregation of dispersed power producing resources will be subjected to the effects of all dispersed power producing resources aggregated on those Elements. Therefore, the criteria applied to the individual dispersed power producing resources will also apply to the aggregation Elements.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-1. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-1. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator output.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the GSU transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the GSU transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the*

> *relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous and Time Overcurrent Relay (50/51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator(s) operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.

Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

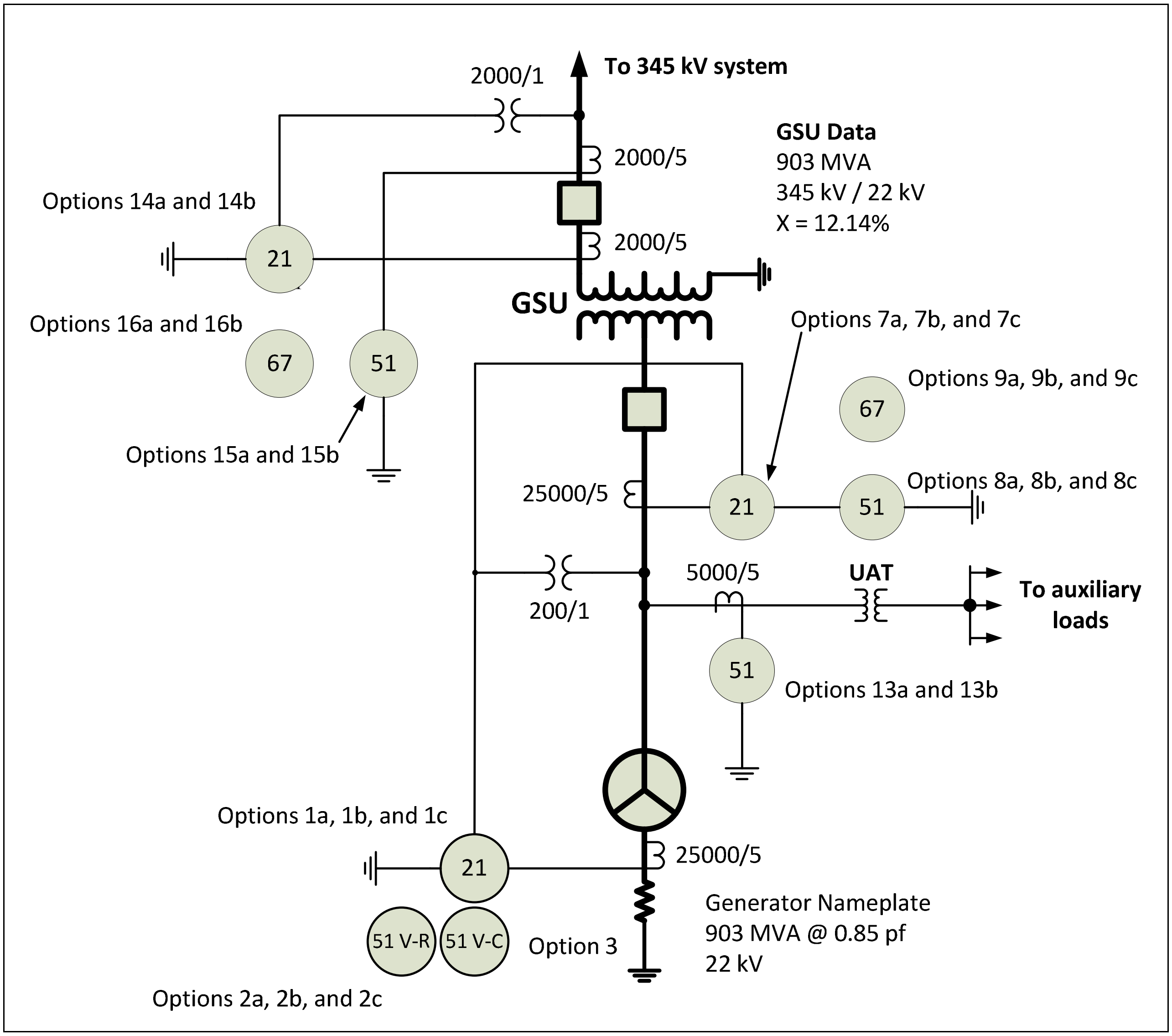


Figure 4. Relay Connection for corresponding synchronous options.

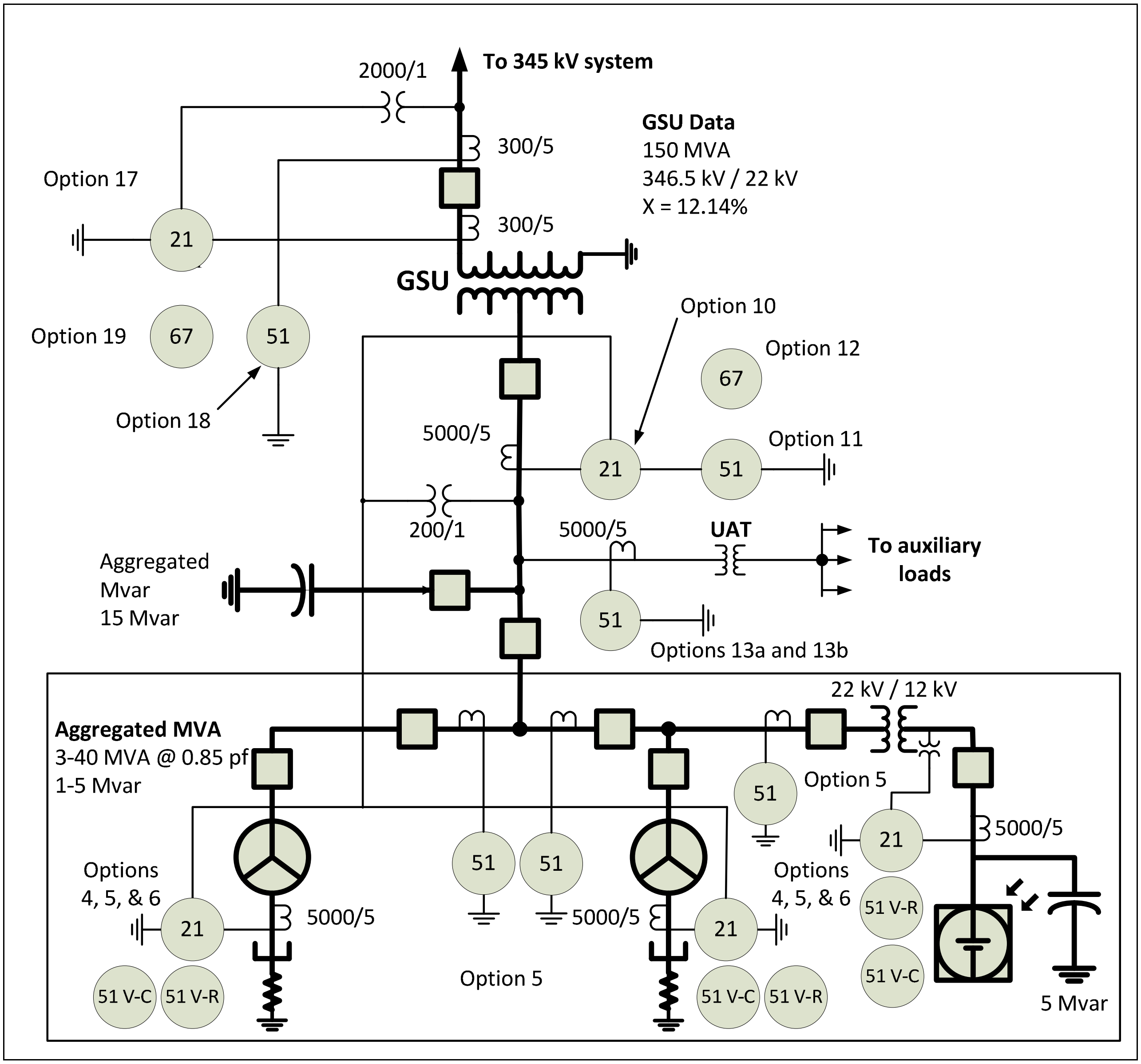


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current (e.g. rated armature current). Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current (e.g. rated armature current). Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150

percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for GSU transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU transformer. Where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the

Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) operation of the relays will cause the associated generator to trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase time overcurrent relaying applied to the low voltage terminals of the UAT are not addressed in this standard. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

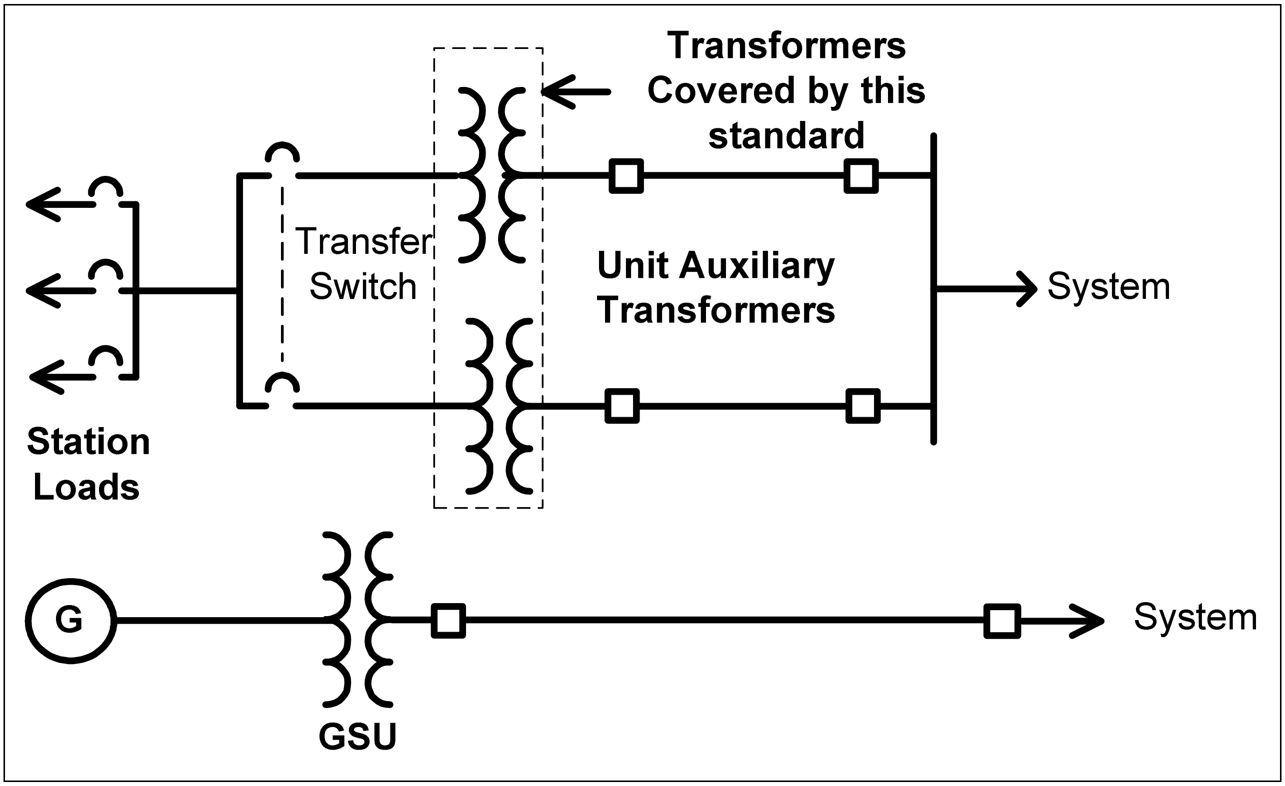


Figure-6 – Auxiliary Power System (independent from generator).

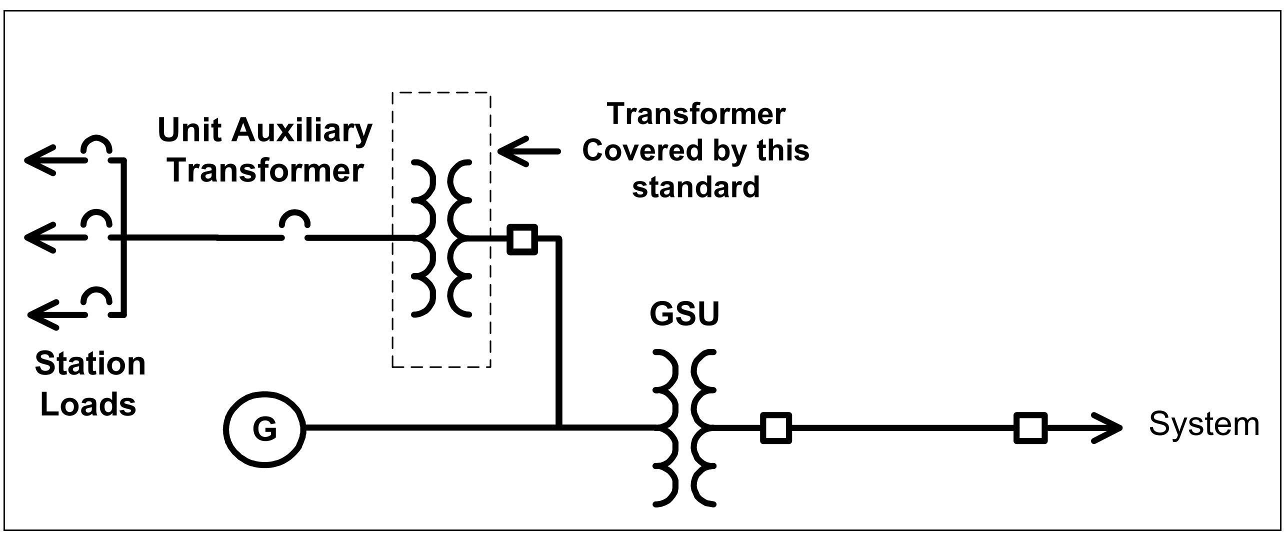


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting pickup compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.(Synchronous Generators) Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.(Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or

dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$

Example Calculations.	
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\dfrac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\dfrac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = 6.7°$$

Eq. (15) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 1b and 7b

Apparent power (S):

Eq. (19) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (23) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0^{\circ} - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

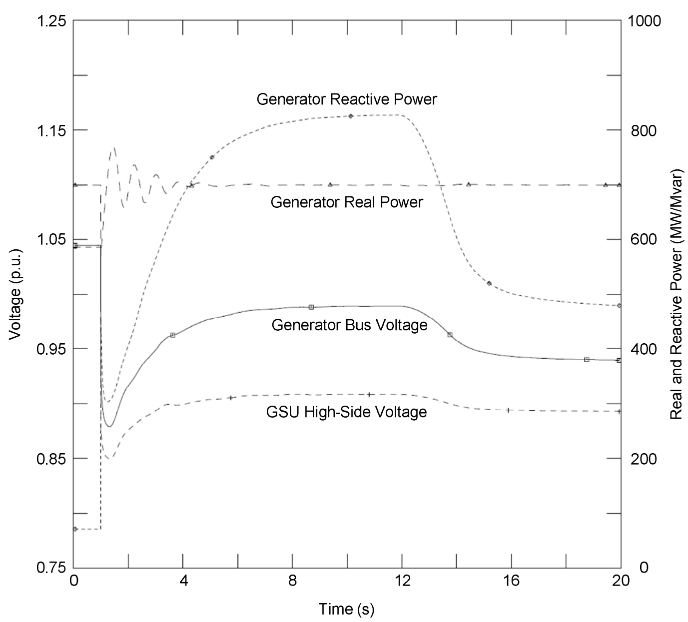
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Example Calculations: Options 1c and 7c

Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (28) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^{\circ} - 49.8°)}$$

Example Calculations: Options 1c and 7c

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 2a

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) or (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51) or (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

In this simulation the following values are derived:

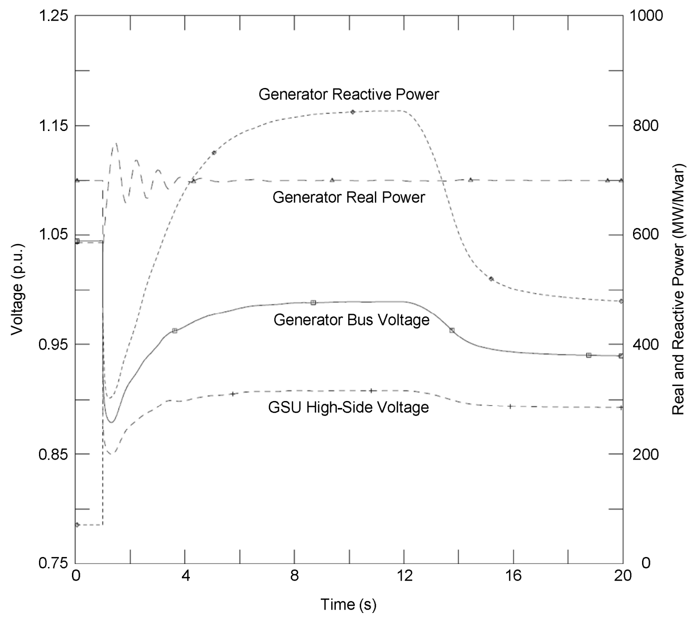
$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

Example Calculations: Option 2c

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Option 2c

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Example Calculations: Option 4

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

Example Calculations: Option 4

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for three asynchronous generators applying a phase time overcurrent (51) or (51V-R) – voltage-restrained relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $I_{sec} = \dfrac{I_{pri}}{CT_{Asynch\_ratio}}$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5:

Eq. (70) $I_{\sec limit} > I_{sec} \times 130\%$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (71) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{synch}):

Eq. (72) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (73) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (74) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (75) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (76) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

Example Calculations: Options 7a and 10

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (77) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (78) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (79) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (80) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 85 to satisfy the margin requirements in Options 7a and 10:

Eq. (81) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (82) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \, \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \, \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0° \, \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (83) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (84) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \, MW$$

$$Q = 1151.3 \, Mvar$$

Example Calculations: Options 8a and 9a

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (85) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (86) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (87) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (88) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (89) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (90) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (91) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (92) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (93) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (94) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Example Calculations: Options 8b and 9b

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (95) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (96) $$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8441 \pm 1.1541}{2}$$

$$\left|V_{low-side}\right| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (97) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (98) $$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\ p.u.$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (99) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9998\,p.u. \times 345\,kV \times \left(\frac{22\,kV}{346.5\,kV}\right)$$

$$V_{bus} = 21.90\,kV$$

Apparent power (S):

Eq. (100) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\,MW + j1151.3\,Mvar$$

$$S = 1347.4\angle 58.7°\,MVA$$

Primary current (I_{pri}):

Eq. (101) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\,MVA}{1.73 \times 21.90\,kV}$$

$$I_{pri} = 35553\,A$$

Secondary current (I_{sec}):

Eq. (102) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\,A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\,A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (103) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\mathrm{sec}\,limit} > 7.111\,A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.178\,A$$

Example Calculations: Options 8a, 9a, 11, and 12

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (104) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (105) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (106) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (107) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri-sync}$):

Eq. (108) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (109) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (110) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (111) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (112) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2^\circ\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (113) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2^\circ\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2^\circ\ A$$

Secondary current (I_{sec}):

Eq. (114) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 94 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 98:

Eq. (115) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

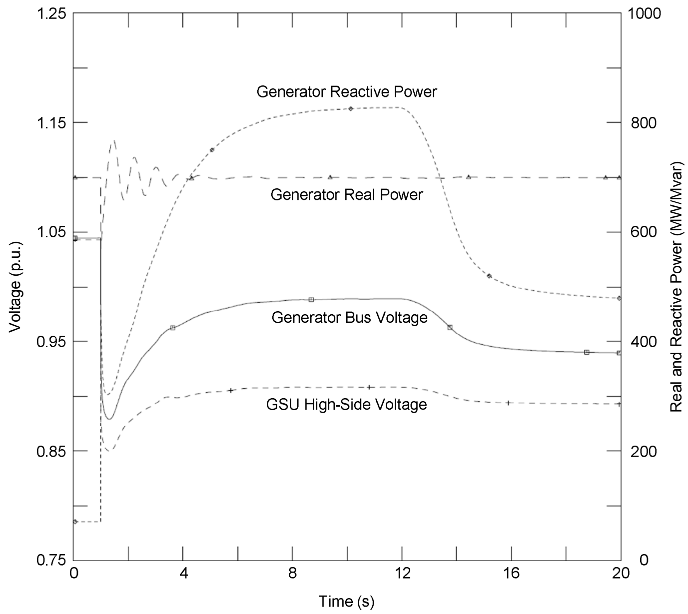
$$Q = 827.4 \, Mvar$$

$$V_{bus} = 0.989 \times V_{gen} = 21.76 \, kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \, MW$$

Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (116) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (117) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (118) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Options 8c and 9c

To satisfy the 115% margin in Options 8c and 9c:

Eq. (119) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10

This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (120) $P = \ 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (121) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (122) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (123) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option10

Primary impedance (Z_{pri}):

Eq. (124) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (125) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (126) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (127) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} <\ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12
Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (128) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (129) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (130) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (131) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (132) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (133) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\,A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\,A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (134) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\,A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\,A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (135) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\,MVA}{1.73 \times 13.8\,kV}$$

$$I_{pri} = 2510.2\,A$$

Secondary current (I_{sec}):

Eq. (136) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\,A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (137) $$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (138) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (139) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (140) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (141) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (142) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (143) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (144) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (145) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

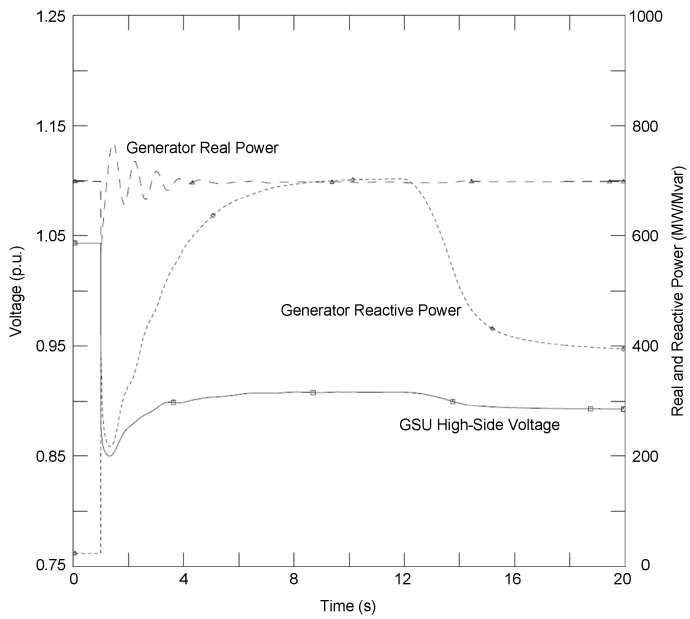
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (146) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Example Calculations: Option 14b

Primary impedance (Z_{pri}):

Eq. (147) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (148) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (149) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (150) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Option 15a represents applying a phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional overcurrent supervisory elements (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer.

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.

Real Power output (P):

Eq. (151) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (152) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (153) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (154) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8^{\circ}\ MVA$$

Primary current (I_{pri}):

Eq. (155) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\,MVA}{1.73 \times 293.25\,kV}$$

$$I_{pri} = 2280.6\angle -52.8°\,A$$

Secondary current (I_{sec}):

Eq. (156) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\,\angle -52.8°\,A$$

To satisfy the 115% margin in Options 15a and 15b:

Eq. (157) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\,\angle -52.8°\,A \times 1.15$$

$$I_{\sec limit} > 6.56\,\angle -52.8°\,A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Option 15b represents applying a phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

In this simulation the following values are derived:

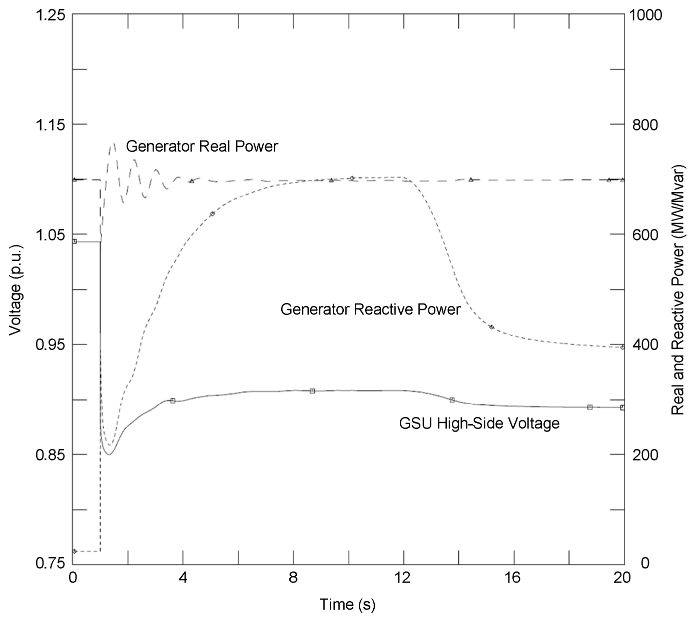
$$Q = 703.6\,Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\,kV$$

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (158) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (159) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (160) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}}$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\,A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (161) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 4.578\angle -45.1°\,A \times 1.15$$

$$I_{\sec limit} > 5.265\angle -45.1°\,A$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (162) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (163) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (164) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (165) $S = P + jQ$

Example Calculations: Option 17

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (166) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (167) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (168) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (169) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

Example Calculations: Option 17

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19
Option 18 represents the calculation for three asynchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, Option 19 may also be applied here for the phase directional time overcurrent relays (67) directional toward the Transmission system for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (170) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (171) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (172) $$V_{nom} = 1.0\ p.u.\times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (173) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (174) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 18 and 19

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (175) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (176) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

EXHIBIT B

Implementation Plan

Implementation Plan

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner, Transmission Owner, or Distribution Provider might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames. One time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays require replacement or removal. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load

encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of proposed PRC-025-1.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner, Transmission Owner, or Distribution Provider will need to: evaluate load-responsive protective relays applied on its Facilities; perform the applicable calculations required by the standard; and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.
9. The Generator Owner, Transmission Owner, and Distribution Provider will need to coordinate activities where multiple owners may need to perform its work under the standard.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

<table>
<tr><th rowspan="2">Requirement</th><th rowspan="2">Applicability</th><th colspan="2">Implementation Date</th></tr>
<tr><th>Jurisdictions where Regulatory Approval is Required</th><th>Jurisdictions where No Regulatory Approval is Required</th></tr>
<tr><td rowspan="2">R1</td><td rowspan="2">Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after applicable regulatory approvals</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities</td></tr>
<tr><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after applicable regulatory approvals</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities</td></tr>
</table>

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including, but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition , shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1 (New)** **R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 (Retirement) R1, Criterion 6. – "Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	

EXHIBIT C

Order No. 672 Criteria

Exhibit C -- Order No. 672 Criteria

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

Proposed Reliability Standard PRC-025-1 achieves the specific reliability goal of decreasing the severity of voltage disturbance during time periods during which generators have been known to trip unnecessarily. The proposed Reliability Standard prevents premature or unnecessary tripping of generators during such periods by setting criteria to ensure generators are able to provide Reactive Power within their dynamic capacity during transient periods. Proposed Reliability Standard PRC-025-1 contains a technically sound means to achieve this goal by requiring applicable entities to apply settings in accordance with the criteria table in Attachment 1 of the proposed Reliability Standard. The Table provides specific setting criteria for load-

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

responsive protective relays in a variety of scenarios. Several options are available to assist Entities in achieving this important reliability goal.

This limits the severity of voltages disturbances as well as preventing the change of the disturbance's character into one from which the Bulk Electric System requires longer to recover. Performance of the proposed Reliability Standard's criteria by the requisite entities will improve the reliability of the Bulk Electric System during disturbances by preventing the reoccurrence of excessive generator tripping.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard applies to Generator Owners, Transmission Owners, and Distribution Providers. The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. The proposed Reliability Standard clearly lists the types of Facilities subject to compliance. Table 1 in the proposed Reliability Standard is clear and provides information by application, relay type, voltage, and pickup setting. This proposed Reliability Standard is designed to comport with proposed Reliability Standard PRC-023-3, which os still under development and scheduled to be filed with the Commission by the end of calendar year 2013.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for the VSL is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSL does not use any ambiguous terminology, and supports uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standard contains a Measure that supports the Requirement by clearly identifying what is required and how the Requirement will be enforced. The Measure is as follows:

> For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard effectively addresses technical issues identified in Reliability Standard PRC-023-2 and makes clear what is required

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5 Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

6 Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

with regard to generator-based relays. As proposed, the standard provides several options and approaches for setting relays allowing opportunity for efficient compliance with this and proposed Reliability Standard PRC-023-3.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. This proposed Reliability Standard is designed address the Commission's concern with generator relay loadability identified in Order No. 733. This standard raises the level of reliability by providing relay loadability requirements for generating Facilities that, along with proposed Reliability Standard PRC-023-3 prevent tripping of generating Facilities for system conditions such as those observed during the August 2003 Blackout.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

Proposed Reliability Standard PRC-025-1 has no undue negative effect on competition. It requires the same performance by the Distribution Provider, Generator Owner, and Transmission Owner in the setting of its load-responsive protective relays to prevent generator tripping when conditions do not pose a direct risk to the generator and associated equipment and will reduce the risk of unnecessary generator tripping—events that increase the severity of disturbances. It also does not unreasonably restrict transmission or generation operation on the bulk power system beyond any restriction necessary for reliability. These setting criteria are intended to allow generation Facilities to be operated to their full capability and do not impose any restrictions on operation of generation Facilities to which the Reliability Standard applies or to overall operation of the Bulk-Power System. Proposed Reliability Standard PRC-025-1 offers general calculations or more advanced simulation for determining settings. This does not create an unduly preferential manner as it allows entities to manually perform calculations, use general business tools, or utilize more advanced analytical tools such as power system modeling and simulation applications.

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transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

9 Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

9. **The implementation time for the proposed Reliability Standard is reasonable.**[10]

The proposed effective dates for the Reliability Standard appropriately balance the urgency to implement the standard against the time needed by those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability, and in cases where existing load-responsive protective relays require replacement or removal, time to design modifications, procure equipment, and schedule necessary Facility outages.

To allow requisite covered Entities adequate and reasonable time to comply with the standard, the implementation period is based on two time frames. The first time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays require replacement or removal. The proposed effective dates are further explained in the proposed implementation plan, attached as **Exhibit B**.

While still under development, the proposed Reliability Standard PRC-023-3 implementation plan will be designed to align with the implementation plan attached to this proposed Reliability Standard. NERC is requesting concurrent approval of the two proposed Reliability Standard in order to properly coordinate implementation timing.

10. **The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.**[11]

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10 Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

11 Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit F** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

EXHIBIT D

Consideration of Issues and Directives

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-13.2 Generator Relay Loadability

Consideration of Issues and Directives

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
NERC Ref: S-10724 Para 106 supported by Paragraphs 104, 105, and 108. **106.** We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability. Para 104, 105, and 108 **104.** We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC-023-1 to address	Order No. 733 (Para 104, 105, 106, and 108)	**Response to P106** The Reliability Standard PRC-025-1 is responsive to paragraph 106 by establishing a new standard that addresses generator unit relay loadability for load-responsive protective relays applicable to generating Facilities for the conditions (depressed voltages) observed during the August 2003 blackout in the northeastern portion of North America. **Response to P104** The Reliability Standard PRC-025-1 is responsive to paragraph 104 by establishing requirements for load-responsive protective relays on generator step-up (GSU) transformers and on unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating units or generating plants. These

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC-023-1. **105.** In light of the EROs statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a		transformers are variably referred to as station power, UATs, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning UATs. The standard is coordinated with the expected outcomes of PRC-023-2 in that it will assure that the applicable equipment will not be removed from service unnecessarily for the conditions observed during the August 2003 blackout in the northeastern portion of North America. **Response to P105** The Reliability Standard PRC-025-1 is responsive to paragraph 105 by developing a new standard to address generator relay loadability according to the filed schedule. This Phase II of relay loadability required an extension of time to complete, extending the deadline to September 30, 2013. A one year extension was granted on February 15, 2012, Docket No. RM08-13-001.

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA. **108.** Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.		**Response to P108** The Reliability Standard PRC-025-1 is responsive to paragraph 108 by establishing a requirement for each Generator Owner, Transmission Owner, and Distribution Provider to apply settings on its load-responsive protective relays for GSU transformers. For GSU transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to the Transmission Planner, and 150% of the unit's Reactive Power capability, in megavoltampere-reactive (Mvar) derived from the generator nameplate megavoltampere (MVA) rating at rated power factor. For GSU transformers connected to asynchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the aggregated generators at rated power factor. Asynchronous generator criteria also include inverter-based installations.

EXHIBIT E

Analysis of Violation Risk Factor and Violation Security Level

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-1, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

EXHIBIT F

Summary of Development History and Complete Record of Development

Exhibit F*—Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard*

The development record for the proposed Reliability Standard is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the team members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted on August 5, 2010 and approved by the Standards Committee ("SC") on August 12, 2010. A revised version of the SAR was approved on November 1, 2010.

B. First Posting

Proposed Reliability Standard PRC-025-1 was posted for a 30-day public comment period from October 5, 2012-November 5, 2012. There were 39 sets of comments, including comments from approximately 112 people from approximately 90 companies representing 8 of the 10 industry segments.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-025-1 based on those comments:

- The word "install" in Requirement R1 is not an industry standard word – the word "install" was replaced with "apply" and Measure M1 was changed to comport with R1;
- The phrase "while maintaining reliable protection" was updated by inserting the word "fault" to make the phrase "while maintaining reliable fault protection;"

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

- The Measure M1 was revised to remove the appearance of adding to the requirement by listing the evidences as examples;
- Potential overlap with the current PRC-023-2 – Transmission Relay Loadability Reliability Standard is being addressed through a proposed revision outlined in the supplemental SAR; and
- A more understandable structure of Table 1 was created for clarity.

C. Second Posting

Proposed Reliability Standard PRC-025-1 was posted for a 45-day public comment period from January 25, 2013-March 11, 2013. There were 55 sets of comments, including comments from approximately 175 people from approximately 102 companies representing 8 of the 10 industry segments. Proposed Reliability Standard PRC-025-1 received a quorum of 76.36% and an approval 54.65%.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-025-1 based on those comments:

- Revised to remove the first occurrence of "generator;"
- Minor revisions to provide clarity in the scope of the standard;
- Inserted section 3.2.5 to provide applicability to Facilities that address Elements utilized in the aggregation of dispersed power producing resources;
- Included language to note that the standard does not require the use of any of the protective functions listed in Table 1, Relay Loadability Evaluation Criteria;
- Removed the Planning Coordinator and inserted the Regional Reliability Organization to comport with the anticipated retirement of MOD-024-1 and MOD-025-1 and the approval of MOD-025-2 in both the text and Table 1;
- Inserted language to address situations where the Generator Owner may combine both asynchronous and synchronous generators on a generator interconnection Facility to provide direction on the evaluation of relay loadability;
- Updated the references to no-load tap changes and on-load tap changers to the generally accepted use of the IEEE terms, deenergized tap changers and load tap changers;
- Added an exception to the standard for Protection Systems that detect generator overloads;
- Added an exception to the standard for Protection Systems that detect transformer overloads;
- Made minor editorial edits to Table 1 text for clarity such as replacing "connected to" with "aggregate" for consistency with other uses;
- Made minor editorial edits to remove hyphens and inserting the word "connected" (e.g., Generator step-up transformer [connected] to asynchronous generators);

- For the application of generator interconnection Facility, reduced the Reactive Power output calculation from 150% to 120% to account for Reactive Power losses in the GSU transformer;
- Updated the implementation information to mimic the table provided in the current PRC-023-2 and proposed PRC-023-3 to delineate the implementation for jurisdictions where regulatory approval is required and in jurisdictions where no regulatory approval is necessary; and
- Inserted language concerning who the Real and Reactive Power is reported to by the Generator Owner to allow a transition from reporting to the Regional Reliability Organization to the Transmission Planner rather than having the Planning Coordinator as identified in the previous posting of the proposed PRC-025-1 standard.

D. Third Posting

Proposed Reliability Standard PRC-025-1 was posted for a 30-day public comment period from April 25, 2013-May 24, 2013. There were 51 sets of comments, including comments from approximately 166 people from approximately 92 companies representing 9 of the 10 industry segments. The proposed standard received a quorum of 81.25% and an approval rating of 69.23%.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-025-1 based on those comments:

- Included the Distribution Provider and Transmission Owner to create a bright line distinction between the development work on PRC-023-3 and the proposed PRC-025-1;
- Replaced “generator interconnection Facility” with “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant;”
- Removed the Regional Reliability Organization references;
- Added the following elements to Options 15, 16, and 18; “Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer;”
- The implementation period for applying settings to load-responsive protective relays that do not require replacement or removal changed from 48 months to 60 months;
- The implementation period for applying settings to load-responsive protective relays that do require replacement or removal changed from 72 months to 84 months; and
- Removed references to PRC-023-3 in VRF/VSL justification.

E. Fourth Posting

Proposed Reliability Standard PRC-025-1 was posted for a 30-day public comment period from June 20, 2013-July 19, 2013. There were 43 sets of comments, including comments from approximately 114 people from approximately 93 companies representing 7 of the 10 industry segments. The proposed standard received a quorum of 85.05% and an approval rating of 72.43%.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-025-1 based on those comments:

- Stakeholders had concerns that section 3.2.4 (Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.) did not take into account station service loads served by the same Elements and would not be truly "exclusive." The drafting team added the sentence "Elements may also supply generating plant loads." To clarify the intent;
- Revised general text to improve clarity based on stakeholder comment.
- Added a section for parallel and multiple line configurations to clarify the issues with determining settings for those possible cases;
- Clarified "full-load current" to note that means the rated armature current of the generator;
- Added a footnote reference to direct the reader to the basis of the overload exclusion;
- Made general revisions to comport with the Applicability clarification;
- Clarified which Options are referring to "Elements utilized in the aggregation of dispersed power producing resources." This scenario is identified in Figure 5, but not clearly in Attachment 1, Table 1; and
- Provided clarifying text about dispersed power producing resources.

F. Final Ballot

Proposed Reliability Standard PRC-025-1 was posted for a 10-day final ballot period on August 2, 2013-August 12, 2013. The proposed Reliability Standard received a quorum of 89.13% and an approval rating of 76.52%.

G. Board of Trustees Approval

Proposed Reliability Standard PRC-025-1 was approved by the NERC Board of Trustees on August 15, 2013.[2]

[2] During discussion, the Board requested that NERC staff investigate whether the application to Unit Auxiliary Transformer Facilities addresses all the load-responsive protective relays that potentially impact the operation of a generating unit or generating plant during the conditions anticipated by the standard. The standard drafting team is examining this issue and will prepare a report for presentation to the Board.

Status:
A final ballot for PRC-023-3 is being conducted from **September 4, 2013** through **September 13, 2013**. If approved, it will be presented to the NERC Board of Trustees for adoption at its November meeting. PRC-025-1 was adopted by the NERC Board of Trustees on **August 15, 2013.**

Background:
The March 18, 2010, FERC Order No. 733, approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes athree-phased approach to standard development.

Phase 2 is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for theGenerator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service.

Phase 1 was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. Phase 3, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Purpose/Industry Need:
During analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This unnecessary tripping has often been evaluated to have extended the scope and/or duration of that disturbance. This was noted, in detail, to be a serious issue in the August 2003 "blackout' in the northeastern North American continent.

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage is widely depressed. In order to support the system during this phase of a disturbance, this standard establishes criteria for setting load-responsive relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from that voltage disturbance. Premature or unnecessary tripping of generators during this period can deepen the severity of the voltage disturbance due to removal of dynamic Reactive Power, and change the character of the disturbance such that it is less recoverable.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 **PRC-023-3** **Clean** | **Redline to Last Posting** | **Redline to Last Approved** **Implementation Plan** **Clean** | **Redline**	**Final Ballot** **Info>>** **Vote>>**	**09/04/13 - 09/13/13** **(closed)**	**Summary>>** **Ballot Results>>**	
Draft 5 **PRC-025-1** **Clean** | **Redline to Last Posting (Redline Corrected 08/05/13)** **Implementation Plan** **Supporting Materials:** **Guideline and Technical Basis** **Clean** | **Redline to Last Posting** **VRF/VSL Justification**	**Final Ballot** **Updated Info>>** **Vote>>**	**08/02/13 - 08/12/13** **(closed)**	**Summary>>** **Ballot Results>>**	

Draft 4 **PRC-025-1** Clean | Redline to Last Posting **Implementation Plan** Clean | Redline to Last Posting **Guideline and Technical Basis** Clean | Redline to Last Posting **Draft 3** **PRC-023-3** Clean | Redline to Last Posting **Implementation Plan** Clean | Redline to Last Posting **Supporting Materials:** Unofficial Comment Form (Word) PRC-025-1 PRC-023-3 **VRF/VSL Justification for PRC-025-1** Clean | Redline to Last Posting Consideration of Issues and Directives for PRC-025-1	**Successive Ballot and Non-binding Poll for PRC-025-1** **Updated Info>>** **Vote>>**	**07/10/13 – 07/19/13 (Closed)**	**Summary>>** **Ballot Results>>** **Non-binding Poll Results>>**	
	30-day Comment Period for PRC-025-1 **Info>>** **Submit Comments>>**	**06/20/13 - 07/19/13 (Closed)**	**Comments Received>>**	**Consideration of Comments>>**
	Initial Ballot for PRC-023-3Info>> **Vote>>**	**07/26/13 - 08/08/13** **(closed)**	**Summary>>** **Ballot Results>>**	
	Join Ballot Pool>>	**06/20/13 - 07/19/13 (Closed)**		
	45-day Comment Period for PRC-023-3 **Info>>** **Submit Comments>>**	**06/20/13 - 08/08/13** **(closed)**		**Consideration of Comments>>**
Draft 3 **PRC-025-1** Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting Guideline and Technical Basis Clean | Redline to Last Posting Draft 2 PRC-023-3 Clean |	**Successive Ballot and Non-binding Poll for PRC-025-1** **Updated Info>>** **Vote>>**	**05/15/13 - 05/24/13** **(closed)**	**Summary>>** **Ballot Results>>** **Non-binding Poll Results>>**	
	Comment Period for PRC-025-1 and PRC-023-3	**04/25/13 - 05/24 13** **(closed)**	**Comments Received>>**	**Consideration of Comments>>**

Redline to Last Posting Implementation Plan Clean | Redline to Last Posting Supporting Materials: Unofficial Comment Form (Word) VRF/VSL Justification for PRC-025-1 Clean | Redline to Last Posting Consideration of Issues and Directives for PRC-025-1 VRF/VSL Justification for PRC-023-3	**Info>>** **Submit Comments>>**			
Draft 2 **PRC-025-1** **Clean | Redline to Last Posting** **Implementation Plan** **Clean | Redline to Last Posting** **Guideline and Technical Basis** **Clean | Redline to Last Posting** **VRF/VSL Justification** **Consideration of Issues and Directives** **Draft 1** **Supplemental SAR for Relay Loadability Order 733 to revise PRC-023-2** **PRC-023-3** **Clean | Redline to Last Approved** **PRC-023-3 Implementation Plan** **Supporting Materials:** **Unofficial Comment Forms (Word)** **PRC-025-1** **Supplemental SAR** **Cost Effectiveness**	**Initial Ballot and Non-binding Poll** **Info>>** **Vote>>**	**03/01/13 - 03/11/13** **(closed)**	**Summary>>** **Ballot Results>>** **Non-binding Poll Results>>**	
	Comment Period **Info>>** **Submit Comments** **PRC-025-1>>** **Cost Effectiveness>>** **Supplemental SAR>>**	**01/25/13 - 03/11/13** **(closed)**	**Pilot CEAP Report** **Comments Received:** **PRC-025-1** **Supplemental SAR**	**Consideration of Comments:** **PRC-025-1>>** **Supplemental SAR>>**
	RSAW Industry Comment Period **PRC-025-1 RSAW>>** **RSAW Feedback Form>>** **Please send RSAW Feedback Forms to:** **RSAWfeedback@nerc.net**	**01/25/13 - 03/11/13** **(closed)**		
	Join Ballot Pool>>	**01/25/13 - 02/25/13** **(closed)**		

Draft 1 **PRC-025-1** **Implementation Plan** **Clean** **Supporting Materials:** **SAR for Relay Loadability Modifications and Additions** **clean | Redline to last posting** **Unofficial Comment Form (Word)** **SAR for Relay Loadability PRC-023-2** **Draft SAR Version 1**	**Comment Period** **Submit Comments>>** **Info>>**	**10/5/2012 - 11/5/2012 (Closed)**	**Comments Received>>**	**Consideration of Comments>>**

All comments should be forwarded to sarcomm@nerc.net.

Draft 1

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 1 of PRC-025-1, Generator Relay Loadability for a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period with Parallel Initial Ballot	December 2012
30-day Formal Comment Period with Parallel Successive Ballot	March 2013
Recirculation ballot	June 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Version	Date	Action	Change Tracking

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive generator protective relays at a level such that generators do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service.
3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities.

   3.2. Facilities: The following Elements of the Bulk Electric System generation Facilities, including those identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]
4. **Background:**

   After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout' in the northeastern North American continent.[2]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability

[1] These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the Guidelines and Technical Basis for more detailed information concerning auxiliary transformers.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

B. Requirements and Measures

R1. Each Generator Owner shall install settings that are in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on each load-responsive protective relay while maintaining reliable protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed.

> Rationale for R1:
>
> Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.
>
> The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.
>
> The term, "while maintaining reliable protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the latest last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	To be determined	To be determined	To be determined	To be determined

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

PRC-025-1 – Attachment 1: Relay Settings

Each Generator Owner that applies load-responsive protective relays shall use one of the following Options 1-17 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay according to its application. The bus voltage is determined by the criteria for the various applications listed in Table 1.

Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor.

Asynchronous generator output pickup setting criteria values are determined by the site's aggregate maximum seasonal gross Real Power capability, in MW, as reported to the Planning Coordinator; and the Reactive Power capability, in (Mvar), as determined by calculating the rated Mvars based on the aggregate MVA at rated power factor and adding the Mvar output of any static or dynamic reactive power devices. Asynchronous generator criteria also include inverter-based installations.

Table 1. Relay Loadability Evaluation Criteria

Relay Type	Option	Application	Bus Voltage	Pickup Setting Criteria
Phase Distance Relay (21) – Directional toward the Transmission System	1	Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Distance Relay (21) – Directional toward the Transmission System	2	Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output - 100% of maximum seasonal gross reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	3	Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation
Phase Distance Relay (21) – Directional toward the Transmission System	4	Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 130% of the total aggregate MVA output at rated power factor

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Time Overcurrent Relay (51V) voltage-restrained	5	Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Time Overcurrent Relay (51V) voltage-restrained	6	Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Time Overcurrent Relay (51V) voltage-restrained	7	Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to Maximum Mvar output determined by simulation
Phase Time Overcurrent Relay (51V) voltage-restrained	8	Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than the current derived from 130% of total aggregate MVA output at rated power factor
Phase Time Overcurrent Relay (51C) – Enabled to operate as a function of voltage (e.g., Voltage controlled relay)	9	Synchronous or asynchronous generators (including inverter installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the nominal generator bus voltage

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Time Overcurrent Relay (51)	10	Generator step-up transformer – Synchronous generators	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of connected generation rated MW
Phase Time Overcurrent Relay (51)	11	Generator step-up transformer – Synchronous generators	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation
Phase Time Overcurrent Relay (51)	12	Generator step-up transformer – Asynchronous generators only (including inverter-based installations)	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 130% of aggregate installed maximum rated MVA output of the connected generators at rated power factor

Table 1. Relay Loadability Evaluation Criteria

Relay Type	Option	Application	Bus Voltage	Pickup Setting Criteria
Phase Distance Relay (21) – Directional toward the Transmission System	13	Generator step-up transformer – Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of connected generation rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	14	Generator step-up transformer – Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	15	Generator step-up transformer – Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Distance Relay (21) – Directional toward the Transmission System	16	Generator step-up transformer – Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 130% of the total aggregate MVA output at rated power factor
Phase Time Overcurrent Relay[3] (51)	17	Auxiliary transformers	1.0 per unit nominal voltage on the high-side terminals of the auxiliary transformer	The element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating

[3] Refer to the Applicability 3.2.3.

Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[4]

The term, "while maintaining reliable protection" in Requirement R1, describes that the responsible entity ("Generator Owner") is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generation plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the responsible entity consider both the requirements within this standard and its desired protection goals, and perform modifications to its protection relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be necessary to replace the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the responsible entity must understand the criteria and application of Table 1, Relay Loadability Evaluation Criteria ("Table 1"), in determining the settings that it must install on each of its load-responsive protective relays to achieve the required generator performance during the transient conditions anticipated by this standard.

Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field forcing," results in the Reactive Power exceeding the steady-state capability of the generator and the resultant increase in apparent power may result in operation of load-responsive generator protective functions, if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased output during field forcing is limited by the field winding thermal withstand capability. The excitation limiter may respond to begin reducing the level of field forcing in as little as one second, but may take much longer, depending on the level of field forcing and the characteristics of the excitation system. Since this time may be longer than the time-delay of the generator backup protection, it is important to evaluate load-responsive protective relay loadability to prevent its operation for this condition during which the generator is not at risk of thermal damage.

[4] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

The criteria established within Table 1, are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other, undesired, behavior occurred.

The dynamic load levels specified in Table 1 under column Pick Up Setting criteria, are representative of the maximum expected apparent power during field forcing with the Transmission system voltage at 0.85 per unit at the high-side of the generator step-up transformer. These values are based on values recorded during the events leading to the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified load operating points are believed to represent conservative, but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltage for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20% of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1 and 2, for example, are based on relatively simple, but conservative calculations. In recognition that not all units are capable of achieving this level of output, Option 3, for example, was developed to allow an entity to simulate the output of a generating unit when the simple calculation is too conservative to achieve the desired protective function setting.

Asynchronous generators, however, do not have excitation systems and will not respond to a Disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. They also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (e.g., Option 4), for induction generator installations.

Phase Distance Relay (Options 1-4)

Generator phase distance relays, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. The Options 1 through 4 establish criteria for phase distance relays to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

Phase distance protection measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. When phase distance protection is applied, its function is to provide backup protection for system faults that have not been cleared by Transmission system circuit breakers via their protective relays.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***which is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition which causes the generator voltage regulator to boost generator excitation for a sustained period that may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally a distance relay setting of 150 to 200% of the generator MVA rating at its rated power factor* (sic: This setting can be re-stated in terms of ohms as 0.66 – 0.50 per unit ohms on the machine base.) *has been shown to provide good coordination for stable swings, system faults involving infeed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine-generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load*

> *encroachment blinders can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two phase distance zones. In this case, the second zone would be set as described above. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the generator step-up transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. Your normal zone-2 time delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and isolated-phase bus with partial coverage of the generator step-up transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

Table 1, Options 1, 2, and 3, are provided for assessing loadability for synchronous generators. The generator-side voltage during field forcing will be higher than the high-side voltage due to the voltage drop resulting from the Reactive Power flow through the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.

Option 1 accounts for the voltage drop across the generator step-up transformer using a conservative estimate of the generator-side voltage. This is based on referring a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer through the turns ratio.

Option 2 uses a calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This option accounts for the voltage drop through the generator step-up transformer, including the turns ratio and impedance.

Option 3 uses a simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The responsible entity must perform simulations to determine the actual performance of its generator. The responsible entity that elects to determine the synchronous generator performance on which to base phase distance relay settings may simulate the response of a generator to depressed Transmission system by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling switching of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator holding the assigned voltage schedule while at 100% of the maximum seasonal gross Real Power capability value as reported to the Planning Coordinator.

Option 4 is based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Since asynchronous generators do not produce as much reactive power as synchronous generators, the voltage rise due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high side nominal voltage to the generator side based on the generator step-up transformer's turns ratio. The aggregate megavoltampere (MVA) output is determined by summing the total nameplate MW and megavoltampere-reactive (Mvar) capability of the generation equipment behind the relay. This should also include any static or dynamic reactive power devices that contribute to the power flow through the relay.

If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability (i.e., field forcing). For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may restrict the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. The examples in Appendix E "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee, illustrate the potential for encroaching on the generating unit capability.

If an entity is unable to meet the criteria established within Table 1, while maintaining reliable protection, the entity will need to utilize different protective relays or protection philosophies such that both goals can be met.

Generator Phase Overcurrent Relay – Voltage Restrained (Options 5-8)

Generator voltage-restrained phase overcurrent relays, which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together.

Table 1, Options 5 through 8, establish criteria for phase overcurrent relays which change their sensitivity as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51R), (51VR), (51V/R), (51V-R), or other terms. The criteria provided for these relays are very similar to those provided for phase distance relays in Options 1 through 4. See clause 3.10 of "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) for a detailed discussion of this protection function.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Phase Overcurrent Relays – Voltage Controlled (Option 9)

Generator voltage-controlled overcurrent relays, enabled as a function of voltage, are applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together, and many other generators were tripped by unknown protection functions.

Table 1, Option 9, establishes criterion for phase overcurrent relays which are enabled as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51C), (51VC), (51V/C), (51V-C), or other terms. See clause 3.10 of "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function.

The criteria for a voltage control setting of less than 0.75 per unit of the nominal generator voltage is based on guidance in "Power Plant and Transmission System Protection Coordination," published by the NERC SPCS. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage is indifferent as to the current setting, and simply requires that the relays not respond for the depressed voltage.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Step-up Transformer Phase Time Overcurrent Relay (Options 10-12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Table 1, Options 10 through 12, establish criteria for the generator protective relays to prevent the generator step-up transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

The stressed system conditions, anticipated by Options 10 through 12, reflect a 0.85 per unit Transmission system voltage; therefore, establishes that the ampere value used for applying the generator step-up transformer phase time overcurrent relay be calculated from the apparent power addressed within the Table 1, with application of a 0.85 per unit Transmission system voltage.

Options 10 and 11 apply to generator step-up transformers connected to synchronous generators. Option 12 only applies to generator step-up transformers connected to asynchronous generators (including inverter-based installations).

Please see clause 3.9.2 of “Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function. However, the setting criteria established within Options 10-12 differ from that suggested in this paper. Rather than establishing a uniform setting threshold of 200% of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Step-up Transformer Phase Distance Relay (Options 13, 14, 15, and 16)

The FERC Order No. 733 paragraph 112, directs that NERC address relay loadability for protective relays applied for system backup protection. In paragraph 114, FERC further explains that their concern applies whether those relays are installed on the generator terminals or on the generator side of the generator step-up transformer. Their concerns regarding those relays connected to the generator terminals are addressed in Options 1, 2, 3, and 4 for the generator itself; Table 1, Options 13, 14, 15, and 16, for generator step-up transformer distance relays address those connected to the generator side of the generator step-up transformer.

The generator protective relays in Options 13, 14, 15, and 16 prevent generator step-up transformer phase distance relays from operating during the dynamic conditions anticipated by this standard.

Auxiliary Transformers Phase Time Overcurrent Relay (Option 17)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of auxiliary transformer(s) that supply normal station service for a generating unit. The Table 1, Option 17, for auxiliary transformers addresses phase time overcurrent relays protecting auxiliary transformers that are used to provide overall auxiliary power to the generating station when the generator is running (regardless of where these transformers are connected). This discussion refers to each of these transformers as a “unit auxiliary transformer” or “UAT.” If the UAT trips, it will result in tripping of the generator itself, either directly or indirectly. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating plant.

Refer to the figures below for example configurations:

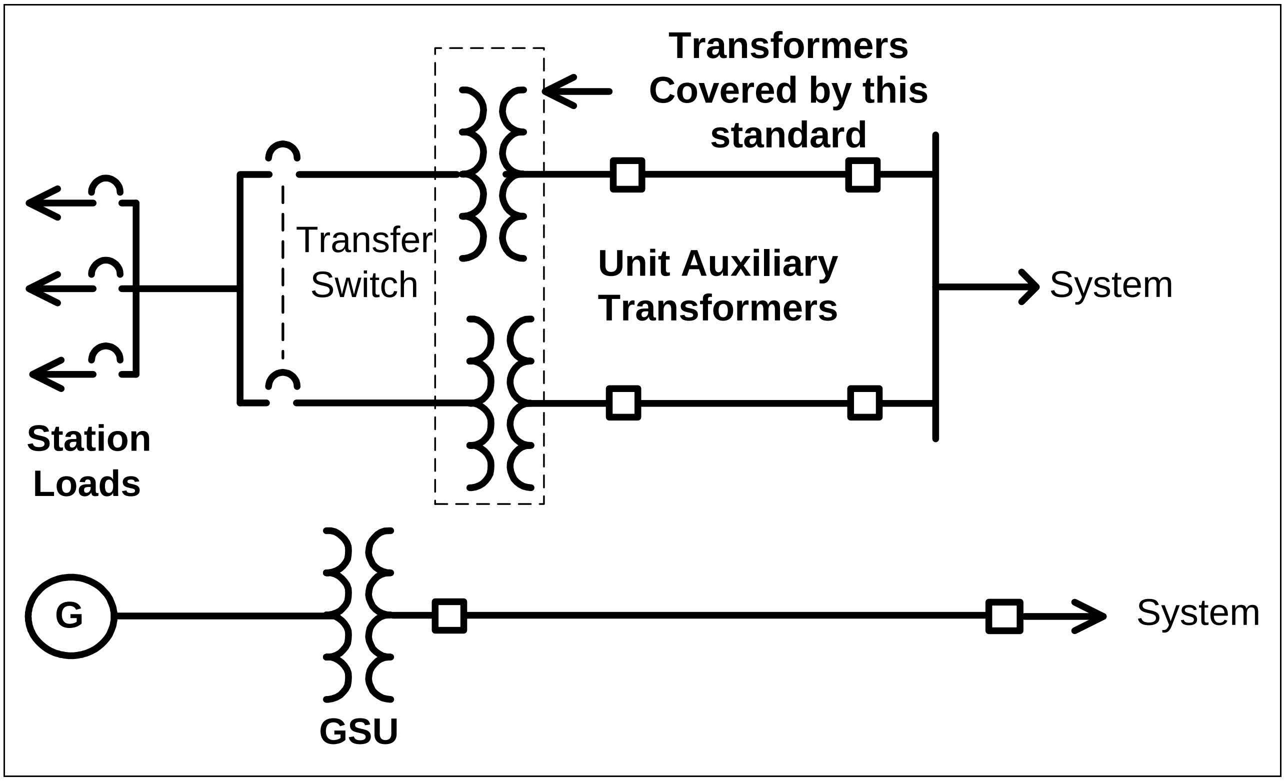

Figure-1 –Auxiliary Power System (Independent from Generator)

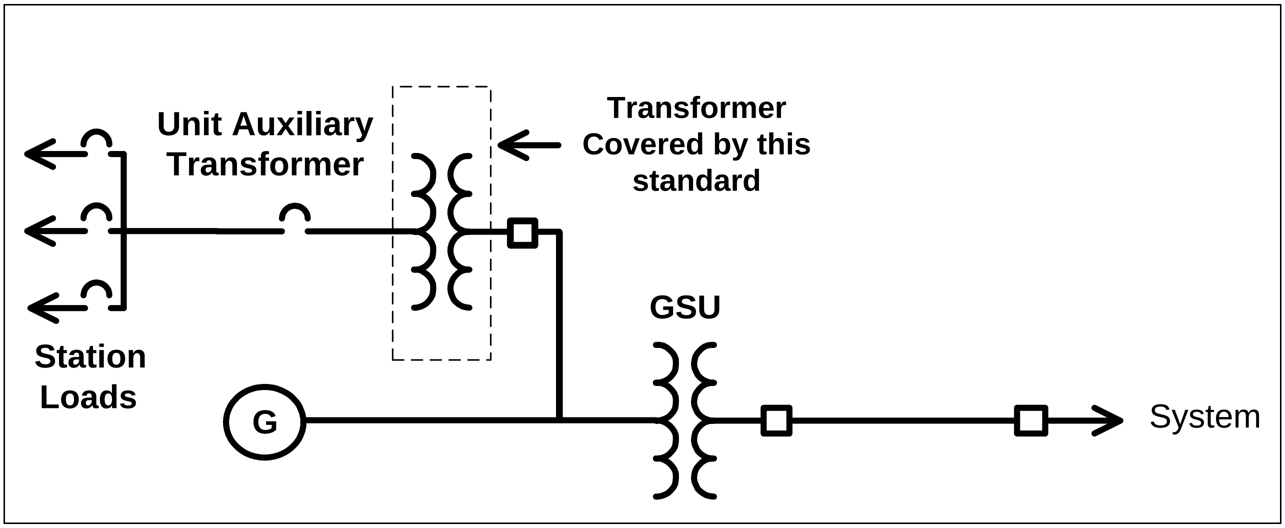

Figure-2 – Typical Auxiliary Power System for Power Plants

The UATs supplying power to the plant's electrical auxiliaries are sized to accommodate for the maximum expected auxiliary load demand at the highest generator output. Although the MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original plant design, the MVA capacity of the transformer may be near full load.

The performance of the auxiliary loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring entities to determine the response of auxiliary loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150% from that used elsewhere in this standard (i.e., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150% of maximum nameplate MVA rating at 1.0 per unit generator bus voltage would provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased auxiliary load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan period reflects consideration of the following:

1. The Generator Owner will likely find it necessary to adjust the existing load responsive protective relay settings on its generation unit(s) to comply with this standard, and it will be necessary for the plant to be off-line in order to make these adjustments.
2. The Generator Owner may find it necessary to replace portions of their existing protective relaying in order to comply with this standard. In such cases, the Generator Owner may need to budget the necessary work, engineer the necessary adjustments, coordinate with other entities, and procure certain materials. Further, the Generator Owner may require an outage of significant duration in order to apply settings, perform necessary testing, and replace any necessary components.
3. It is not beneficial to reliability for a Generator Owner to remove a generation unit from service solely to achieve compliance with this standard. Additionally, the implementation recognizes that the time between scheduled outages depends on the nature of the generation plant and may be as long as 24 months. Due to the time between scheduled outages, the implementation plan also considers the time required to budget and procure the necessary material; therefore, provides a 48-month period for becoming 100% compliant with the standard.
4. For a Generator Owner with a sizable generation fleet, the implementation plan provides time for staggered outages.

General Considerations

To be developed in draft 2 based on industry comment.

Applicable Entities

- Generator Owner

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

N/A

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load responsive protective relays subject to the standard

The Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant 48 months beyond the effective date of this standard.

Load responsive protective relays which become applicable to the standard

The Generator Owner that owns load responsive protective relays that become applicable to this standard, (not because of the actions of the Generator Owner, including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action), shall be 100% compliant on the first day of the first calendar quarter that is 48 months beyond the date such change is effected by an applicable regulatory authority, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1** **R1.** Each Generator Owner shall install settings that are in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on each load-responsive protective relay while maintaining reliable protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in Order No. 733, paragraph 102.	

Standard Authorization Request Form

Title of Proposed Standard	Relay Loadability Order 733
Request Date	8/5/2010
SC Approval Date	8/12/2010
Revised Date	11/1/2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☒	New Standard
Primary Contact	Stephanie.monzon@nerc.net	☒	Revision to existing Standard
Telephone Fax	610-608-8084	☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.
Industry Need FERC directed NERC to develop modifications related to Relay Loadability by specific deadlines in Order No. 733. Attachment 1 to the SAR contains the directives and associated deadlines. <u>PRC-023-1 Directed Modifications</u> The Commission directed a number of changes to the approved standard including a test to be applied by Planning Coordinators to determine applicability to elements operated at less than 200 kV. This test will be included in PRC-023-1 either in the form of a Requirement or as an attachment to the standard. <u>Generator Step-up and Auxiliary Transformers</u> The Commission directed the ERO to develop a new Reliability Standard addressing generator relay loadability, with its own individual timeline, and not a revision to an existing Standard. <u>Protective Relays Operating Unnecessarily Due to Stable Power Swings</u> The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes miscoordination of the protection system and is inconsistent with entities' obligations under existing Reliability Standards. In this Final Rule the Commission decided not to direct the ERO to modify PRC-023-1 to address stable power swings. However, because both NERC and the U.S.-Canada Power System Outage Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, the Commission directed the ERO to develop a Reliability Standard that requires use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relays that cannot meet this requirement.
Brief Description This SAR's scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Detailed Description

Phase I: Develop modifications to PRC-023-1- Transmission Relay Loadability by March 18, 2011 to address the following directives from Order 733:

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.
- p 162 . . . consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- P. 224… direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

In Phase I of the project, the NERC Relay Loadability standard drafting team will either modify the PRC-023-1 Reliability Standard to incorporate the directed modifications or will propose equally efficient and effective alternative approaches that address the Commission's reliability-related concerns. *(In parallel with this effort, NERC plans to convene a panel of industry subject matter experts to develop a straw man proposal for the test Planning Coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the Bulk Power System. The panel will collect industry feedback on the straw man test using the current standards development process that will be incorporated into Requirement R3 of PRC-023-1 by the Standard Drafting Team.)*

Phase II: Develop a new Standard Addressing Generator Relay Loadability
In Phase II of the project, a new Reliability Standard will be developed by the end of 2012 to address the subject of generator relay loadability in support of NERC's filing indicating it would develop such a standard and to address the following directive from Order No. 733:

- p. 108 . . . consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.

As indicated in NERC's Order No. 733 clarification and rehearing request, NERC believes adding additional requirements to the PRC-023 standard in addition to developing a new Reliability Standard to address generator relay loadability could lead to confusion over applicability and the possibility of conflicting requirements. Therefore, NERC proposed in its clarification and rehearing request to address the issue of generator relay loadability in a new Reliability Standard, separate and distinct from the PRC-023 Reliability Standard, which is intended to address relays that protect transmission elements. Subject to the Commission's response to NERC's pending clarification and rehearing request, NERC plans to address generator relay loadability in a new Reliability Standard for applications where the relays are set with a shorter reach to protect the generator and the generator step-up transformer, and for applications where the relays are set with a longer reach to provide backup protection for transmission system faults. The standard drafting team will use relevant sections of the NERC technical reference document, Power Plant and Transmission System Protection Coordination Section 3.1 and Appendix E to develop the requirements by which generator relay loadability will be assessed.

<u>Phase III: Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings</u>
In Phase III of the project, a new Reliability Standard will be developed to address the subject of protective relay operations due to power swings to address the following directive from Order No. 733 by the end of 2014:

- p. 150 - develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
PRC-023-1	Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization (“ERO”), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines.
New Reliability Standard	Development of a New Standard Addressing Generator Relay Loadability
New Reliability Standard	Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 - Order No. 733 – Action Plan and Timetable

Note that the scope of the SAR is limited to addressing the directives highlighted in the table below.

Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines and directed NERC to develop requirements to address issues related to Relay Loadability. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The following table lists the FERC directives in Order No. 733 and for each directive associates it with a project phase. Note that some of the tasks within each phase will be managed by NERC staff, not the standard drafting team.

Paragraph	Text	Project Phase/ Timeline
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Phase I -- by March 18, 2011
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Phase I -- Note NERC's pending request for rehearing filed on April 19, 2010 regarding this directive.
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Phase I – by March 18, 2011
105	In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard.	Phase II – by the end of 2012
108	Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.	Phase II – by the end of 2012
150	However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and,	Phase III – by the end of 2014

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
	when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.	
162	We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Phase I – by March 18, 2011
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Phase I – by March 18, 2011
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Phase I – by March 18, 2011
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Phase I – by March 18, 2011
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Phase I – by March 18, 2011
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Phase I – by March 18, 2011
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Phase I – by March 18, 2011
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Phase I – by March 18, 2011

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
284	We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section.	Phase I – by March 18, 2011
297	Finally, we direct the ERO to assign a "high" violation risk factor to Requirement R3.	Filed with the Commission on April 19, 2010
308	Consequently, we direct the ERO to assign a single violation severity level of "severe" for violations of Requirement R1.	Filed with the Commission on April 19, 2010
310	Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from "lower" to "severe" to be consistent with Guideline 2a.	Filed with the Commission on April 19, 2010
311	Finally, we direct the ERO to assign a "severe" violation severity level to Requirement R3.	Filed with the Commission on April 19, 2010

Standard Authorization Request Form

Title of Proposed Standard	Relay Loadability Order 733
Request Date	8/5/2010
SC Approval Date	8/12/2010
Revised Date	11/1/2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☒	New Standard
Primary Contact	Stephanie.monzon@nerc.net	☒	Revision to existing Standard
Telephone Fax	610-608-8084	☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

Industry Need

FERC directed NERC to develop modifications related to Relay Loadability by specific deadlines in Order No. 733. Attachment 1 to the SAR contains the directives and associated deadlines.

PRC-023-1 Directed Modifications
The Commission directed a number of changes to the approved standard including a test to be applied by Planning Coordinators to determine applicability to elements operated at less than 200 kV. This test will be included in PRC-023-1 either in the form of a Requirement or as an attachment to the standard.

Generator Step-up and Auxiliary Transformers
The Commission directed the ERO to develop a new Reliability Standard addressing generator relay loadability, with its own individual timeline, and not a revision to an existing Standard.

Protective Relays Operating Unnecessarily Due to Stable Power Swings
The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes miscoordination of the protection system and is inconsistent with entities' obligations under existing Reliability Standards.

In this Final Rule the Commission decided not to direct the ERO to modify PRC-023-1 to address stable power swings. However, because both NERC and the U.S.-Canada Power System Outage Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, the Commission directed the ERO to develop a Reliability Standard that requires use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relays that cannot meet this requirement.

Brief Description
This SAR's scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Detailed Description

Phase I: Develop modifications to PRC-023-1- Transmission Relay Loadability by March 18, 2011 to address the following directives from Order 733:

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.
- p 162 . . . consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- P. 224… direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

In Phase I of the project, the NERC Relay Loadability standard drafting team will either modify the PRC-023-1 Reliability Standard to incorporate the directed modifications or will propose equally efficient and effective alternative approaches that address the Commission's reliability-related concerns. *(In parallel with this effort, NERC plans to convene a panel of industry subject matter experts to develop a straw man proposal for the test Planning Coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the Bulk Power System. The panel will collect industry feedback on the straw man test using the current standards development process that will be incorporated into Requirement R3 of PRC-023-1 by the Standard Drafting Team.)*

Phase II: Develop a new Standard Addressing Generator Relay Loadability
In Phase II of the project, a new Reliability Standard will be developed by the end of 2012 to address the subject of generator relay loadability in support of NERC's filing indicating it would develop such a standard and to address the following directive from Order No. 733:

- p. 108 . . . consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.

As indicated in NERC's Order No. 733 clarification and rehearing request, NERC believes adding additional requirements to the PRC-023 standard in addition to developing a new Reliability Standard to address generator relay loadability could lead to confusion over applicability and the possibility of conflicting requirements. Therefore, NERC proposed in its clarification and rehearing request to address the issue of generator relay loadability in a new Reliability Standard, separate and distinct from the PRC-023 Reliability Standard, which is intended to address relays that protect transmission elements. Subject to the Commission's response to NERC's pending clarification and rehearing request, NERC plans to address generator relay loadability in a new Reliability Standard for applications where the relays are set with a shorter reach to protect the generator and the generator step-up transformer, and for applications where the relays are set with a longer reach to provide backup protection for transmission system faults. The standard drafting team will use relevant sections of the NERC technical reference document, Power Plant and Transmission System Protection Coordination Section 3.1 and Appendix E to develop the requirements by which generator relay loadability will be assessed.

<u>Phase III: Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings</u>
In Phase III of the project, a new Reliability Standard will be developed to address the subject of protective relay operations due to power swings to address the following directive from Order No. 733 by the end of 2014:

- p. 150 - develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
PRC-023-1	Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines.
New Reliability Standard	Development of a New Standard Addressing Generator Relay Loadability
New Reliability Standard	Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 - Order No. 733 – Action Plan and Timetable

Note that the scope of the SAR is limited to addressing the directives highlighted in the table below.

Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines and directed NERC to develop requirements to address issues related to Relay Loadability. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The following table lists the FERC directives in Order No. 733 and for each directive associates it with a project phase. Note that some of the tasks within each phase will be managed by NERC staff, not the standard drafting team.

Paragraph	Text	Project Phase/ Timeline
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Phase I -- by March 18, 2011
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Phase I -- Note NERC's pending request for rehearing filed on April 19, 2010 regarding this directive.
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Phase I – by March 18, 2011
105	In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard.	Phase II – by the end of 2012
108	Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.	Phase II – by the end of 2012
150	However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and,	Phase III – by the end of 2014

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
	when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.	
162	We agree with the PSEG Companies and direct the ERO to consider “islanding” strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Phase I – by March 18, 2011
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Phase I – by March 18, 2011
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Phase I – by March 18, 2011
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Phase I – by March 18, 2011
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Phase I – by March 18, 2011
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Phase I – by March 18, 2011
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Phase I – by March 18, 2011
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard’s scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Phase I – by March 18, 2011

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
284	We also direct the ERO to remove the exceptions footnote from the “Effective Dates” section.	Phase I – by March 18, 2011
297	Finally, we direct the ERO to assign a “high” violation risk factor to Requirement R3.	Filed with the Commission on April 19, 2010
308	Consequently, we direct the ERO to assign a single violation severity level of “severe” for violations of Requirement R1.	Filed with the Commission on April 19, 2010
310	Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from “lower” to “severe” to be consistent with Guideline 2a.	Filed with the Commission on April 19, 2010
311	Finally, we direct the ERO to assign a “severe” violation severity level to Requirement R3.	Filed with the Commission on April 19, 2010

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation

Formal Comment Period Open: October 5, 2012 – November 5, 2012

Now Available

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, November 5, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, November 5, 2012.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Background

The March 18, 2010, FERC Order No. 733, approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phased approach to standard development.

Phase 2 is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (36 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)
Comments (36 Responses)
Question 1 (32 Responses)
Question 1 Comments (34 Responses)
Question 2 (26 Responses)
Question 2 Comments (34 Responses)
Question 3 (29 Responses)
Question 3 Comments (34 Responses)
Question 4 (29 Responses)
Question 4 Comments (34 Responses)
Question 5 (0 Responses)
Question 5 Comments (34 Responses)

Individual
Jeffrey Streifling
ATCO Power
Yes
The requirement is clear enough -- the ambiguities arise in the attachment.
No
I think you are trying to handle the case where the transmission system voltage becomes depressed to 0.85 pu. This does not cause the voltage at the armature terminals of the generator to change, except in a transient time frame (or if the AVR is in manual or drooped). During the transient time frame, the armature terminal voltage would be depressed to 1-(0.15 * (Xd'/(Xd'+Xt)) pu volts (Xt=transformer reactance (pu), Xd'=transient machine reactance, pu), but this will reduce, not increase, the reactive power output, so the worst case for voltage support is in the steady-state time frame after the AVR corrects the voltage. After the AVR corrects the voltage, the armature terminals will return to approximately 1 pu voltage (or whatever it was set at before the disturbance) and the VAR outflow will be the transformer MVA times 0.15/%IZ (0.15 = 1-0.85 = amount voltage is depressed, %IZ transformer rated impedance). (This is just Ohm's law applied to the voltage difference across the output transformer between 1 pu armature voltage and 0.85 pu system voltage.) There is no reason to require simulations to find this value; it can be easily calculated. (The 150% assumption is another way of saying, "assume the output transformer impedance is 10% on a base of the generator maximum real power" -- and it often isn't.) If you want to be sure to cover all possible real power loadings, draw a horizontal line across the PQ plane parallel to the P axis at this value. (This is true unless we assume a voltage depression will only happen at certain loadings -- why? which ones?) This horizontal line corresponds to a mho circle with a diameter equal to Xt/0.15, 90 degrees MTA, and zero offset. So if the goal is, "permit generators to ride through 0.85 pu transmission voltage depressions without tripping on 21 relays", then require that 21 settings lie inside a mho circle with a diameter/reach of Xt/(0.15 * 1.15), 90 degrees MTA, and zero offset. (The 1.15 is the 115% calibration fudge factor.) The technical basis does not support asking for more than this, and asking for less will not accomplish the apparent objective unless we can somehow guarantee that we don't care about spurious trips at certain loadings (which may be due to power swings.) In my opinion, analysis should precede simulation.
No
There are three issues: (1) on-load tap changers for output transformers are not handled, (2) the 150% reactive outflow assumption is not appropriate when using the calculation option as you can calculate the actual VAR outflow for a 0.85 pu voltage depression quite easily from the transformer impedance unless initial conditions with heavy VAR flows are assumed, and (3) the initial conditions for the simulation are not specified (full load and unity power factor with all voltages at 1 pu?) and the conditions for simulating the voltage depression are not specified (no swings or close-in faults?)
Yes
NOT APPLICABLE IN MY JURISDICTION
Get rid of the 150% assumption. It can be calculated directly from transformer impedance. Get rid of the special cases -- there are too many, such as load tap changers, that you are not handling. Simply require that generators' 21 relays be set to ride through the consequences of a 0.85% transmission voltage depression with 115% fudge factor, and specify the loading range you care about for special cases. This works out to a mho circle, diameter=Xt/(0.15 * 1.15), MTA=90 degrees, zero offset. Compliance verification is a straightforward engineering

exercise.
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
Yes
Yes
Yes
Since this standard isn’t enforceable until 48 months after approval, why not make the effective date 48 months after approval? This would reduce confusion concerning Registered Entities’ requirements for performance (such as outage scheduling and early adoption) during the 48 month implementation period.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
No
In the case where existing protective relay replacement may be necessary, 48 months does not provide adequate time to budget, design, coordinate, procure materials, and schedule the work that would have to be done during outage of sufficient duration. Suggest extending the Implementation Plan duration to 60 months.
Individual
Thad Ness
American Electric Power
Yes
No
AEP has the following concerns regarding the settings options. The 0.85 per unit transmission bus voltage will never be seen by Generators with a delta connection to the Generator Step Up transformer. In order to drop the generator bus voltage to support the 0.85 transmission bus voltage, the unit would need to reduce the Real Power output. Even with reducing the Real Power output and increasing the Reactive Power output, the unit may not be able to withstand the lower voltage. Motors may trip out when connected to a lower generator bus voltage, which could cause additional operating issues and potentially leading to a trip of the unit itself.
No
Generation relay settings typically use the generator bus voltage for calculations. Options 2, 3, 6, 7, 10, 11, 12, 14, 15 and 17 are all expressed as .85 per unit of the transmission system, but should instead be referenced in regards to the generator bus voltage (as Options 1, 4, 5, 8, 9, 13, and 16 are). Phase distance relays (21) listed in Table 1 should be excluded from any requirements in PRC-023-2- Transmission Relay Loadability. The phase distance relays included in Table 1 can only have settings that will be compliant with one set of requirements not both. Inclusion of these relays in PRC-023-2 and PRC-025-1 would pose a conflict in settings. Also the out of step relays (78) were listed in PRC-023-2. However, AEP believes that these relays should also be included in Table 1 as a requirement in addition to being an exclusion from PRC-023-2. “Seasonal gross Real Power capability” needs to be explicitly defined.
No
Due to the expanded scope of this project and the resulting (proposed) requirements, a significant amount of research and studies may need to be performed in order to properly inventory the existing relays and determine

their settings. This is not an automated process, and would require extensive print reviews and field verification. The proposed implementation plan emphasizes the time needed to change the relay settings, but deemphasizes the time and effort required to inventory the relays, determine their current settings, and perform the calculations required to determine the new settings. For entities with a large generating fleet, this phase alone could take four years or more to accomplish. Again, this would include the time and resources necessary to actually make those setting changes in the field. Rather than requiring that all research and implementation be completed within 48 months, a time period much too short to perform the work necessary to meet the requirement, AEP believes this standard should instead utilize the precedent of a phased-in approach over 10 years (for example, 50% complete in 4 years, 75% in 7 years and 100% in 10 years). In addition, the work required for this project requires a specific expertise held by a limited number of subject matter experts, and who are also needed to implement other NERC standards and support ongoing reliability efforts. This further supports the need to extend the time allotted beyond four years.
Are transformers which are independent of the generator bus, and are fed from the grid, in scope? Figure 1 seems to infer the inclusion of such devices, but if so, that is not made explicit within the description provided in 3.2.3 and Note 1. Both 3.2.3 and Note 1 need to be more specific or refer to an attachment for examples. This standard does not explicitly state which auxiliary transformers are in scope. AEP recommends clearly identifying whether the standard is applicable to Reserve Auxiliary Transformers. In addition, Footnote 1's second sentence should be modified to state "Loss of these transformers will result in the generator's immediate removal from service." The scope of this draft is inconsistent with the title and purpose with respect to generator protective relays as opposed to generation relays. The phrase "generator relay" has a specific meaning to a relay engineer, and encompasses only a subset of the generation relays covered under this standard.
Individual
Michael Falvo
Independent Electricity System Operator
No
a. Requirement R1 seems clear but replacing the word "install" with "implement" or "determine" would seem more appropriate that the settings are not exactly "installed". If the SDT accepts this proposed change, then conforming changes need to be made to M1 and throughout the entire standard. b. The language in M1 seems unclear to convey the evidence needed to be provided to demonstrate compliance with R1. We suggest M1 be revised to: For each load-responsive protective relay, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed (suggest to replace it with determined or implemented) in accordance with PRC-025-1 – Attachment 1: Relay Settings.
The proposed effective date in the implementation plan may not clearly address a potential conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that the sentence be re-arranged as follows: [First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees.]
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
Entities may have situations where appropriate equipment protection cannot be met and accommodate the load-responsive requirements of Attachment 1. For these rare cases there should be some provision established to allow the Entities to maintain compliance. The wording of R1 should be changed to clarify that the relay settings applied to load responsive relays must meet or exceed the requirements in Attachment 1. The present wording could be interpreted to require that the load responsive relay settings must be set exactly as prescribed in Attachment 1.
No
Considering Figures 1 & 2, it is unclear whether the intent is to include station auxiliary transformers that feed plant loads when the unit is offline or in the process of startup. An exception should be made for transformers that do not feed plant loads during normal unit online operation.
No
Paragraph 2 of Attachment 1 starting with "Synchronous generator output pickup setting criteria values are determined……" seems to contradict Table 1 regarding the calculation of reactive power output. The paragraph

implies that reactive power capability is calculated using the rated power factor however Table 1 implies that it is calculated as a function of rated MW output. It would greatly enhance understanding of Table 1 if some examples calculations. This would allow entities to be confident that they were interpreting the wording of the requirements correctly.
No
The 48 month time period may not allow enough time to engineer and then schedule the work necessary to implement the changes. The work required to implement new relaying schemes may be intensive if new relays need to be installed. This type of work requires extended outages that may not occur on an annual or even bi-annual basis. The implementation plan should be modified to at least 60 months.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
No
We would suggest that the table be broken up into different tables based on the application of the relay. For example one table for synchronous machines, one table for GSUs, one table for AUX transformers etc..
Yes
Group
Pepco Holdings Inc. & Affiliates
David Thorne
No
Requirement R1 and the wording in Attachment 1 require the GO to install settings on “each load responsive protective relay” in accordance with Attachment 1, Table 1. The standard should make it clear that it does not apply to any load responsive relay (i.e., phase overcurrent protection) that is armed only when the generator is disconnected from the system, or enabled only during generator start-up (i.e., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, open breaker flashover schemes, etc.). Nor should it apply to any phase fault detector relays employed to supervise phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) providing the distance element is set in accordance with the criteria outlined in the standard.
No
Section 3.1 and Appendix E of the NERC SPSC Technical Reference Document “Power Plant and Transmission System Protection Coordination” describes two separate loading points that should be examined to ensure adequate generator relay loadability during extreme system conditions. One is the loading condition chosen in PRC-025-1 (MW = rated MW ; MVAR = 1.5 x rated MW). The other loading condition is with a lower power output, but with a higher var output (MW= 0.4 x rated MW ; MVAR = 1.75 x rated MW). The SPCS document illustrates that depending on the maximum torque angle setting of the distance element that this second loading condition may become the limiting criteria. The Technical Basis and Guidelines in PRC-025-1 refers to this SPCS document several times, but it does not mention this second loading condition, or the rationale for ignoring it when developing the chosen setting criteria.
No
1) Options 1, 5 and 13 should be eliminated, or a qualification should be added that these options may only be used if the generator step-up transformer reactance is greater than some specified threshold amount. It is true that due to the voltage drop across the transformer, the generator voltage will be higher than the system voltage. This can be seen from the following equation: Vgen = Vsys + Igen x (j Xt). Assume the generator is operating at a loading condition of S = 1.532@56.31 pu MVA, which is the maximum anticipated loading condition identified both in this standard, as well as in the SPCS document (ref. Appendix E). Assume the generator voltage Vgen is 0.95@0 pu, as allowed in Options 1, 5, and 13. Since S = VI*, Igen can be found as 1.613@-56.31 pu. By then solving for Vsys, one can see that Vsys will be greater than 0.85 pu, whenever Xt is smaller than 0.076pu (Xt < 7.6%). While most GSU transformers have a reactance equal to, or greater, than this value, some may not. Since all loadability criteria must be based on a system voltage of 0.85 pu, the choice of Vgen = 0.95 pu is appropriate only if the application is restricted to GSU’s with sufficient reactance to ensure the application results in a

corresponding system voltage of 0.85 pu, or lower. Options 2, 3, 6, 7, 14, and 15 are not an issue, because they assume a system voltage of 0.85 pu and then require a calculation, or simulation, to obtain the corresponding generator voltage to be used in the evaluation. Finally, if the SDT decides to retain Options 1, 5, and 13 then the Guidelines and Technical Basis section should be revised to address the technical justification for the choice of a 0.95 pu generator voltage. 2) The ANSI number 51V-R should be used instead of 51V to represent voltage restrained overcurrent relays, and 51V-C should be used instead of 51C to represent voltage controlled overcurrent relays. Using 51V-R and 51V-C avoids confusion, since 51V is often used to represent both types of relays. Also the 51V-R and 51V-C terminology is consistent with that used in the SPCS Technical Reference Document. 3) In the Guidelines and Technical Basis portion of the standard it states "If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics." However, the standard does not provide any specific criteria, or methodology, on how to evaluate relay loadability if these techniques are employed. Table 1 simply states that the 21 element (assumed to be a non-offset mho element) should be set with a maximum reach less than the apparent impedance described, apparently regardless of the setting of the maximum torque angle of the relay. If blinders, or load encroachment techniques were used to accommodate the one specific loadability point described in the standard, aren't there other loadability constraints that also need to be addressed? The Technical Basis portion of the standard points out the concern that altering the shape to achieve a longer reach may restrict the capability of the unit when operating at a real power output other than 100%. Therefore, to cover all applications, the PRC-025-1 standard should describe loadability criteria irrespective of the type, or shape, of the impedance characteristic used. To accomplish this, perhaps a better set of setting criteria would be as follows: "The phase distance protective characteristic should be set, assuming a generator voltage as specified in the column labeled bus voltage, so as to not operate under any of the following three loading conditions: a) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (100% of Maximum MW; Reactive Power equal to 150% of rated MW). b) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (40% of Maximum MW; Reactive Power equal to 175% of rated MW). c) Generator supplying power (as measured at the generator terminals) within its published capability curve." Plotting these three constraints on the R-X impedance plane would allow one to choose a phase distance characteristic (with, or without, load encroachment, or blinders) that would be immune from operating under these specific loading conditions. The third condition would effectively limit the reach of the element so as to not restrict the reactive capability of the unit. This last issue is very important, since in the latest draft of PRC-019 the coordination of the phase distance element with the generator reactive capability curve was specifically removed, implying that it would be addressed in the PRC-025 loadability standard.
Yes
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
No
(1) There is potential for double jeopardy with PRC-025-1 and PRC-023-2. PRC-023-2 also applies to relays on GSU transformers under 100kV. Collectively, applicability section 4.2.1.6 and Attachment A, 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." With this proposed standard, a GO/GOP could be found in violation of both PRC-023-2 and PRC-025-1 for not having appropriate relay loadability settings. We strongly suggest that the SDT consider revising PRC-023-2 to remove all references to Generators in order to avoid any possible instances of double jeopardy. This would be consistent with FERC Order 733, paragraph 106, "we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability." If generator loadability is going to be addressed in its own standard, then it should not overlap with transmission relay loadability and PRC-023. (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls and elimination of zero-defect expectations). To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. As an example, what happens if a GO miscalculates their setting or inadvertently uses the wrong setting for one unit? This should not be a violation, per se, if the GO discovers it and corrects it. (3) We are concerned that this standard also duplicates the proposed PRC-024-1 of Project 2007-09 Generator Verification. Proposed PRC-024-1 requires a GO to ensure its voltage protective relaying does not trip as a result of a voltage excursion. Does the voltage control relaying include Phase-Time Overcurrent Relay (51V) voltage-restrained from Table 1 in Attachment 1 of proposed

PRC-025-1? Is the 0.85 pu voltage identified in the same table not a voltage excursion? If so, this duplication needs to be eliminated. (4) The standard needs some clear flexibility built into it to deviate from the settings in Attachment 1. Consider an example where a GO sets its phase distance relay on its synchronous generator to meet option 1 and an event causes the unit to trip anyway. The GO should be allowed to reassess and apply an appropriate setting even it if deviates from the Attachment 1 relay settings.
No
(1) Paragraph 102 of FERC Order 733 does not provide adequate rationale for attachment 1. Paragraph 102 in the Order is discussing Entergy's treatment of GSU and auxiliary transformers. This question is inaccurate and needs to be clarified in order to provide an appropriate answer. (2) If the drafting team is referring to paragraph 104, by addressing GSU and auxiliary transformer loadability is addressed in a timely manner and in a way that is coordinated with the outcomes of PRC-023-1, we feel there is more coordination that must be done. Currently, PRC-023-2 is now in effect and potentially has applicability requirements for GSUs and auxiliary transformers. For example, applicability section 4.2.1.6 and Attachment A 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." The drafting team must separate the standards to avoid overlap. While we understand that the Commission did not require a separate standard, now that NERC that decided to approach this issue by developing PRC-025-1, it needs to revise PRC-023-2 as well. (3) The technical document that is referenced, "NERC Technical Reference on Power Plant and Transmission System Protection Coordination" explicitly states that "there is limited information available that directly addresses which protection functions are appropriate for BES conditions and which were undesired operations." This document is prefaced with the fact that the authors are unsure of what are appropriate settings for protective relays; rather it addresses the coordination of each of the generator protection functions with the transmission system protection. This is not adequate rationale.
No
(1) We find the criteria confusing and needing further clarification. First, we suggest dividing the table into multiple tables based on the relay type and application. This will make it clear that GO does not have 17 options but rather has only three options for Phase Distance Relays (21) protecting synchronous generators. Second, we are confused about the difference in the bus voltage column for options 1 and 2. Both options apply to the generator bus and voltage is calculated from the high side of the generator step up (GSU) voltage. Option 1 allows the voltage to be set at 0.95 pu and option 2 allows the voltage to be set at 0.85. Option 2 mentions using the GSU impedance in addition to the turns ratio to calculate the generator bus voltage from the high side whereas option 1 only mentions the turns ratio. If the intention is to include the GSU impedance in one calculation and not the other, does it make sense to have a voltage difference of 10%? To drop voltage 10% across a GSU would require a very high impedance transformer. Please provide further clarification. As currently defined, we believe that option 1 will always be selected because it is simply less restrictive. We note that similar issues exist between Options 5 and 6 and Options 13 and 14. We assume the voltage identified in the bus voltage column of options 10-12 applies to the generator bus. It is not clear if the impedance of the GSU is to be considered for these options. We assume it would be but there is so much less information provided than in the other options so it is not clear and is not explained in the technical guidelines.
No
(1) The implementation plan is unreasonable in the amount of time needed to have generation units comply with the standard, especially with the considerations of having to replace existing protective relays, meeting budgetary concerns, coordination with other entities, the time for procurement, and planning outages to complete the necessary work. We suggest 60 months. (2) As mentioned above, there are overlaps with this standard and the applicability section and implementation plan for PRC-023-2. If a generator was subject to PRC-023-2 as a result of being designated by its Planning Coordinator, it would have the "later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date." The drafting team needs to review the applicable time frames, modify PRC-023-2 and provide a clear and understandable timeline that does not have conflicting standards interfering with its implementation. (3) We strongly suggest that the drafting team review PRC-023-2's implementation plan for GO/GOPs and modify both standards to avoid overlap, confusion, and as discussed above, double jeopardy.
(1) We have concerns with the drafting team's approach of requiring replacement of legacy relays for the sake of complying with its proposed standard. This additional strain on resources will have an adverse impact for smaller entities. Smaller entities do not have unlimited budgets and it is difficult to justify the replacement of working equipment just to comply with a regulation. The regulators need to consider reevaluating the threshold that is needed to comply with this standard. If a protection relay is not broken, there should not be a reason to replace it. There is not sufficient justification that having a modern advanced-technology relay with extra functionalities to have a reliability benefit that is commensurate with the cost. (2) We suggest the drafting team complete the VSL table and provide a draft RSAW of this standard. PRC-023-2 is currently in effect and there is no guidance or RSAW posted, which results in a tremendous amount of confusion on how to comply with the standard. We strongly suggest that the SDT plan for how the industry will need to comply with PRC-025-1 and provide a sample

RSAW. Also, if this standard is results-based, then is it possible to consider internal controls for the responsible entity to correct relay settings without consequences of self reporting? (3) We disagree with the setting of a high VRF for Requirement R1. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with the NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. A Medium VRF is more appropriate. (4) We disagree with the statement "that it may be necessary to replace the legacy relay with a modern advanced-technology" on page 14 in the Guidelines and Technical Basis section. Section 215(i)(2) is very clear that the ERO or Commission are not authorized to order construction. Thus, a standard cannot compel relay replacement. (5) There is text in the comment form regarding using a Method 1 or Method 2 for relay loadability. We can find no mention of these methods in the standard or Guidelines and Technical Basis. The methods actually require calculating loadability at two operating points. While one of the points appears to be Pick-up Setting Criteria in Table 1 of Attachment 1, the other is not referenced anywhere in the standard. Please include this section in the standard as appropriate or remove it from the comment form as its purpose is very confusing. (6) Thank you for the opportunity to comment.
Group
North American Generator Forum Standards Review Team
Jim Watson
Agree
North American Generator Forum Standards Review Team
Individual
Travis Metcalfe
Tacoma Power
Yes
Yes
No
Referring to Attachment 1, Table 1, Options 2, 3, 6, 7, 14 & 15, what current is to be applied through the transformer impedance? Referring to Attachment 1, Table 1, Options 10, 11, 13, 14 & 15, should "Real Power output – 100% of connected generation reported" be changed to something like "Real Power output – 100% of maximum seasonal, aggregate gross MW reported to the Planning Coordinator"? Referring to Attachment 1, Table 1, Options 10, 11 & 12, could an exception be granted if the 51 elements are directional toward the generation system? Referring to Attachment 1, Table 1, Option 17, should "the element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating" be changed to something like "the element shall be set greater than 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating"?
Yes
Referring to the first paragraph of Attachment 1, Options 1-17 are not truly exclusive options. Options 1-3, Options 5-7, Options 10 & 11, and Options 13-15 each appear to be exclusive options. However, an entity may, for example, need to apply Options 1, 2 or 3 together with Options 10 or 11 together with Option 17. Consider separating Table 1 into multiple tables, each table based upon a different combination of relay type and application. Each option within each table would then be exclusive.
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
Yes

No additional comments.
Group
Detroit Edison
Kent Kujala
No
The intent of the requirement is clear, but the specifics of how to accomplish it are not. Not sure of the meaning of “performance” in this context.
No
With the exception of Auxiliary Transformers, this standard appears to be concerned with relay elements that operate for power flow toward the transmission system. Distance elements and directional overcurrent relays not “looking” toward the transmission system should not be in scope. Perhaps a statement to this effect in the Technical Basis would be beneficial.
No
Please provide setting examples for each type of relay (21, 51V, etc) using both real and reactive power criteria to clarify how Table 1 should be applied. Also, drawings showing location of applicable relays (CT and PT input sources) would be helpful. Reactive power criteria expressed in terms of MW is confusing.
No
Suggest that allowing 72 months to become 100% compliant would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
The objectives of the following NERC Standards closely match the objectives of the proposed standard, MOD-024, MOD-025(pending regulatory approval) and PRC-019 (Standard under development). Entergy is currently validating the maximum generator capability under SERC criteria for MOD-024 and MOD-025. This validation requires coordination with applicable load responsive relays.
Group
MRO NSRF
Will Smith
No
The NSRF is concerned that Measure M1 does not take into consideration situations in which existing relay settings are already in compliance with the standard but the setting calculations are not dated and/or the actual date that the settings were installed is not known. To better align with the risk-based requirement, the NSRF recommends M1 be revised to only require evidence showing that the relays settings were in compliance prior to the enforcement date. M1. For each load-responsive protective relay in accordance with PRC-025-1 – Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed in compliance with Requirement R1.
No
Recommend the phrase “while maintaining reliable protection” be removed as it introduces ambiguity into R1. Although the SDT attempts to clarify the phrase within the “Guidelines and Technical Basis”, the NSRF is concerned that the phrase’s inclusion will only result in future requests for Interpretation as entities are forced to explain and defend their desired protection goals. Rather than relyon the “Guidelines and Technical Basis”, werecommendthe following changes to R1 be made: R1. Each Generator Owner shall install settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection.
No

The NSRF agrees with the criteria described in Option 1 through 17 in Table 1, however, we recommend that the Table 1 be broken up into different tables based on the application and relay type. For example, there should be a table for synchronous machines, and one for GSUs, and etc. This would add clarity to Table 1. The addition of the new tables would require that the Application Guidelines section to refer to the new tables be revised.
Yes
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
It is clear the Generator must determine and install settings on its load-responsive protective relays in accordance with PRC-025-1.
No
Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.
No
Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.
Yes
LADWP agrees the Implementation Plan to install load-responsive protective relay settings is achievable in 48 months.
For the Transmission Relay Loadabiltiy Program, examples and job aids were provided to establish a uniform method to calculate relay settings. Examples and job aids should also be included for Generator Relay Loadability.
Individual
Saul Rojas
New York Power Authority
No
There was no mention of load responsive relays on an Exciter PPT which is connected to the terminal side of the Generator. There was also no mention of any load responsive relays connected to the ISO Phase Bus between the Generator and the Unit Auxiliary Transformer or the secondary side of the Unit Aux Transformer.
No
For the Unit Auxiliary Transformer, the Technical Basis and Guidelines does not take into account the 51 element being set below 150% of rated but with a significant time delay setting to provide backup protection for the feeder protection.
No
Yes for Option 1-16; No for Option 17 as stated in Question 2.
Yes
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) It is not clear what this question means by the "performance of Requirement R1". If it means that Requirement R1 (and Measure M1) is clear, then yes it is. (2) R1: The phrase 'while maintaining reliable protection' is extremely

ambiguous. We noted that in the rationale, the reader is referred to the Guidelines for elaboration on this phrase. The discussion in the Guideline did little to clarify in our opinion; it discusses balancing the standard and the entity's desired protection plan. Is the standard not mandatory and the entity's overall plan for reliability and protection needs to incorporate the satisfaction of this standard (and others)? (3) M1: The measure as drafted fails to address whether the entity missed installing relays that are required by Attachment A, it is only looking for evidence specifically related to those relays that were installed in accordance with Attachment A.
Yes
No comment.
No
(1) For all 21 - Phase Distance Relays (Option 1 – 4 and Option 13 – 16): The setting criteria did not mention the maximum reach angle of the impedance element setting. Should this be considered and clarified? (2) For 51V – Phase Time Overcurrent Relays, voltage-restrained, (Option 5 & 6): Following this setting criteria could make detecting faults on the high side of the step-up transformer very difficult especially considering that transient or synchronous machine impedance (X'd or Xd instead of X"d) is used for fault calculation. (3) For the 51 relays on the step-up transformers (Option 10): Following this setting criteria could mean that the pickup setting could be 175% of nameplate rating of the transformers. Should there be any concern with the transformer overload and mechanical damage as a result? Also, the 175% setting is not consistent with the 150% number in the Transmission Relay Loadability standard. (4) The "Bus Voltage" criteria are not clearly defined and should be clarified. For example, in Option 1, the generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage would vary depending on the current going through the transformer. Also, option 2 in the table makes reference to "on the high side" and option 1 in the table makes reference to "of the high side". Should these all read 'of'? (5) Given 'gross MW' and 'terminal voltage', how would we calculate current in order to calculate the generator bus voltage? (6) What is meant by "maximum seasonal gross MW"? Is this the nameplate MW? Is this the MW calculated for MOD-024? If so, a reference should be made to this standard.
Yes
Although we agree with the implementation plan, the Applicable Entities should match the language in the standard i.e. Generator Owners 'that applies….' The language in the Implementation Plan section is awkward in that they refer to 'protective relays applicable to this standard' when it would seem to make more sense to refer to 'protective relays to which this standard applies'.
(1) Regarding "Applicability", it is not clear what type of auxiliary transformers should be included as the "Applicable Facilities". For example, if the auxiliary transformer is NOT the only supply to the generator, does the standard still apply to this auxiliary transformer? (2) On page 7 of 22, the following sentence is unclear: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in Megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor". Manitoba Hydro suggests rewording this sentence for clarification. Additionally, should "rated MW" be changed to "rated MVAR'? (3) On page 3, A Introduction, Purpose: We find the purpose quite poorly worded as it stands. It is written in absolutes (i.e. generators do not trip, disturbances that are not damaging) which is quite different than the wording used in the Background to describe the standards (i.e. that did not apparently pose a direct risk). It would seem more appropriate to use language that discusses the purpose as opposed to the outcome. For example, language similar to "To set load responsive generator protective relays at a level designed to prevent tripping of generators during system disturbances that do not apparently pose a direct risk to the generator in order to prevent the unnecessary removal of the generator from service.' (4) On page 3, A Introduction, Applicability, 3.1.1: The standard uses the term Generator Owner in terms of functional entities. However, the definition of Generator Owner only makes reference to owner of generating units. Does that still work with 3.2.2 and 3.2.3 which includes Elements other than generating units? (5) On page 3, A Introduction, Background: Does this 'Background' section become part of the standard once finalized? (6) Attachment A: The opening line should refer to each Generator Owner that applies load-responsive protective relays on the Facilities listed in 3.2 in order to be consistent with the applicability section of the standard itself. (7) Revisions or Retirements to Already Approved Standards: There is a reference to Order NO. 733, paragraph 102. We believe that this needs some elaboration because we are not sure that paragraph sets out the requirement that is in the standard.
Group
pacificorp
ryan millard
Yes
Yes
No

PacifiCorp thermal facilities use impedance elements as backup generators, generator bus and GSU protection where the element does not reach through the GSU. This approach results in impedance magnitudes that are significantly lower than those outlined in the Attachment 1 options. It may be beneficial to generator protection engineers if the standard provides registered entities with an option to calculate the impedance reach of the 21 element when it is based on the GSU impedance. Furthermore, while Options 1-4 & 13-16 in Table 1 specify how to determine the generation facility maximum rating and the per-unit bus voltage to perform the impedance reach calculation, these options are missing: (1) the load (or power factor) angles at which the impedance element reach must be evaluated to ensure compliance, and (2) recommendations as to how to set load-encroachment element blinders. PacifiCorp recommends that this information be incorporated into the "Guideline and Technical Basis" section of PRC-025-1 to ensure compliance, using Standard PRC-023-2 "Reference Document" as a model.
Yes
The use of the term "Bulk Electric System generation Facilities" in the Applicability Section 3.2 of the standard is not explicitly defined. PacifiCorp recommends that the Standards Drafting Team include generator size to further refine the applicability of facilities under this standard.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP ("ICLP") agrees that the instruction is clear in both R1 and M1, but does not agree that the language meets the intent of a "risk-based requirement." The concept, as we understand it, is to focus on the quality of the process which manages the implementation of the settings – not a confirmation that the settings are always perfectly compliant. There is no risk at all inherent in R1, excluding that to the unfortunate Generator Owner who happens to miss-set a single relay. We suggest a preface to R1 similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". This will allow some flexibility when a rare error takes place – while accounting for those entities whose internal controls are not sufficient to the task. In addition, the language addresses those situations where a NERC-compliant setting is not possible without placing equipment or safety at risk.
Yes
From a technical perspective, Ingleside Cogeneration found this section was soundly grounded. However, we believe that there is no rational basis that the standard apply to generators which have minimal impact on BES reliability – analogous to the 200 kV voltage threshold for transmission lines in PRC-023-2. The justification needs to be captured in the Technical Basis and Guidelines section, although the criteria itself would appear in the Applicability section. Secondly, there needs to be further discussion concerning the interaction of the relay loadability thresholds with those required under Project 2007-09 Generation Verification – particularly PRC-024-1 and PRC-019-1. At present, every one of these standards are written in a manner that calls for the Generator Owner to comply with their requirements, and to figure out how to make them all work together. Even though we agree that the ultimate goal to improve generator availability will greatly serve BES reliability, ICLP does not believe this kind of approach is reasonable – and may lead to violations even when the GO is heavily committed to the task.
Yes
No
Similar to PRC-024-1, ICLP believes there needs to be an allowance for those equipment types which cannot accommodate the Table 1 settings. In particular, the variation in the ancillary systems which support the generator is significant – and 48 months will not be sufficient to address every situation.
ICLP believes that NERC's Compliance organization should be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason.
Individual
Timothy Brown
Idaho Power Company
Yes
Yes
Yes

Yes
Based on the language of Section 3.2.3, which describes the applicable facilities, we believe some addtional clarification should be added to Footnote 1. Many modern static excitation systems have a sizable dedicated transformer. We believe a mention of these excitation transformers would provide needed clarification.
Group
Southern Company (Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation Energy Market)
Shammara Hasty
No
The requirement is clear - the protective relay setting specifications are not acceptable. We believe that using "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, our desired protection level is more conservative so that generation equipment is not allowed to be operated in overloaded conditions. Our experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specificed in Table 1 and not result in undesirable nuisance tripping.
No
The rationale seems to ignore the fact that most generators do not operate any of their equipment beyond the manufacturer's ratings in overloaded conditions. The practices suggested by Table 1 seem to be patterned on transmission line loading practices, which are different than the practices used by generators. Generator step up transformers and station auxiliary transformers are generally not allowed to be subjected to short term overload conditions. We disagree with the suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing philosopy of protection used by many companies has proven (over multiple decades) to be adequate for protecting our equipment and providing reliable power supply to customers. The NERC Glossary states the following definition for Equipment Rating: "The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner." The acceptable amount of risk to power equipment evident through margin in the protection settings rests with the equipment owner. We are concerned that the NERC standards will take this away from the equipment owner. This is especially concerning where automatic protection is required and must operate quickly to prevent significant major equipment damage. Reliance on operator intervention to protect the equipment, in this case, is not practical. Adequate margins of protection must be allowed to be maintained in the automatic trip settings. We believe adequate protection is a fundamental tenet for BES reliability to ensure the equipment can be restored to service quickly.
No
Fundamentally, requiring entities to relax preferred protection levels on their equipment with no method of (possible) damage cost recuperation due to more liberal protection settings is not fair to the entities that may incur repair/replacement costs. We believe that Option 17, related to station auxiliary transformers, is unwarranted, excessively liberal in overload allowance, and does not belong in this standard. The station auxiliary power consumption does not directly contribute to the generator overload ability for supporting system disturbance events. Requiring a station auxiliary transformer HSOC (high side overcurrent) relay to be set at the level specified in Option 17 of Table 1 is not justified. We have, for many years, successfully set the station auxiliary transformer HSOC relay pick up value at a much lower value and have experienced very few misoperations. The MW value used in the calculation specifics of Table 1 is unclear. We suggest that the MW value used for the calculations be that realized with applying the generator nameplate MVA rating with the rated power factor also found on the generator nameplate. In the draft standard, the MW value to be used is referred to by many different names, including: •Maximum seasonal gross MW reported to the Planning Coordinator •Rated MW •Total nameplate MW •100% of Connected generation reported Establishing the MW value as suggested above removes all confusion to the GO as to which MW value to use, provides a standard method to use, and is close enough to the other values listed to provide the desired generator loading ability. Table 1 is much too complicated. Options 1-4 and Options 13-16 could easily be combined into one set of four options by modifying the Application column. (For example, the combined Options 1 and Option 4 Application column could be labeled "Synchronous Generator or GSU Xfmr – Synchronous Generator".) Further, Options 1-3 and Options 13-15 should be reduced into one row that specifies the Generator Bus Voltage criteria and the Pickup setting criteria. The additional methods listed (Options 2, 3, 14, 15) simply confuse the issue. (For example, it is not clear which entity is

required to perform a simulation in Options 3, 7, and 15. GO's generally do not have the system simulation software or the system data required to perform this simulation.) For the rows of Table which remain after this simplification, one calculation example per row would be valuable to demonstrate the intented calculation method. We are concerned that the setting limits specific in Table 1 are too liberal to provide adequate overload protection to our generating plant equipment. The required minimum sensitivities for the relaying shown in Table 1 for all units based on a minority (20%) representation of unit capability to provide Q forcing ability results in forcing owners of generators to relax typical relay settings that result in loss of adequate overload protection. Entities should be allowed to protect their equipment from overload rather than be forced to allow a specific amount of overload.
No
The implementation plan for execution of Requirement R1, as written, is too short. This requirement will cause GOs to have to check calculations for every relay in the scope of Table 1 for all of its facilities. Checking the setting limits agains the equipment safety levels will take significant time. Equipment procurement, where necessary, and unit outage availability will dictate the exact time required to address the scope of the applicability. It is recommended that the implementation time be increased to 7 years.
Yes. In Applicability Section 3.2, we disagree with the specifier "including those identified as Blackstart Resources in the TOP's system restoration plan". The additional small units this may draw in to the scope of this standard are not large enough to be significant contributors to correcting frequency and voltage perturbations on the transmission network. The word "overall" does not add any value to applicability section 3.2.3. If the voltage restrained overcurrent relay is the primary relay of concern (as noted from the 14 Aug 2003 disturbance), perhaps the solution is to require that they are replaced with alternative types of relaying rather than by specifying the desensitizing setting specifications. We have real, historical cases where a generator back-up overcurrent relays set at 115 to 130% of the unit rating have saved the units that were exposed to either a low-level, close transmission faults or excitation system malfunctions. A possible solution to generator relaying modifications to provide the maximum allowable loadability for supporting system disturbance events may be to remove all voltage restrained/controlled overcurrent relays and replace them with a standard 51 function. This relay could be set just under the generator ANSI overload curve to protect the unit from low level overload. This would give plenty of area for swings while still protecting the generator. The 21 function could then be adjusted to pickup at 180 to 200% of the units MVA rating with appropriate time delay to coordinate with transmission Zone 3 relays. An alternative solution to specifying the generator relay settings is to allow the PRC-001 standard (currently under draft) to take care of the desired coordination between generator relaying and transmission system relaying. In that standard, the GO and TO must confer with one another regarding the coordination of the generator relaying and the transmission system relaying. The loadability issue of generators, we believe, can be adequately resolved by the coordination requirements to be contained in PRC-001.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Group
Dominion
Mike Garton
Yes
Yes
Yes
No
In the case where existing protective relay replacement may be necessary, Dominion does not feel that 48 months

provides adequate time to budget, design, coordinate, procure materials, and schedule the work in an outage of sufficient duration. Dominion suggests that 60 months may be more appropriate in this instance.
Group
Duke Energy
Greg Rowland
No
1) R1 states that protection must meet the criteria and be reliable - this is not possible. Protection is often considered an artform, since it includes making compromising decisions between dependability and security. This standard, by its nature, is biased toward security. It requires relays to be set such that they can no longer be depended upon to prevent potential damaging operating conditions. 2) In its current form, this standard seems to disregard the factor of time, as it relates to equipment withstand for the specified system conditions. For example, Table 1 will require 51T relays on the GSU not to pickup before 2.2pu (for a machine rated .9pf), even though the transformer through-fault protection curve of IEEE C57.12 does not support continuous operation at that point and the generator stator thermal limit, per IEEE C50.13, is less than 10 seconds. Requiring the GO to permit operation of equipment outside American national equipment standards is incongruent with improving the reliability of the BES. 3) In section M1 on pp4/22: reword to "(2) Record Settings"
No
It is difficult to comment on the criteria, as we are not familiar with the train of thought used to derive them. Not all of the criteria are described in the Technical Basis section.
No
1) If such a table is used; RELAY TYPE should simply be the type of element, such as "Phase Distance - 21", and APPLICATION should be the elements use, such as "Applied on synchronous generator, set to trip for faults in the system direction." Further, the SDT should not separate BUS VOLTAGE and what is called PICKUP SETTING CRITERIA - Together these are defining the system conditions for which the relay is not supposed to pickup. 2) It is not clear what the intent of the 115% factors specified in Table 1 are. If these are for coordinating margin, this should be expressed so coordination margins are not doubled. 3) We recommend using the common designations of 51VC for voltage controlled inverse time overcurrent elements and 51VR for voltage restrained inverse time overcurrent elements. 4) SDT should specify criteria in standard engineering terms. The use of language such as "VArs equal to 150% of rated MW" is not clear. It would be better to specify "Rated Watts at .55 pf lagging." 5) We do not understand the differences between several of the options, such as between option 1 & 2. Option 1 is not aligned with Appendix E of the technical guide, and no commentary is provided within the standard. SDT is creating criteria that are outside the mainstream - it must provide more technical information on what the intent and rationale is for each criteria. 6) The intent of options 13-16 is not clear. Are these for 21 elements on the high voltage of GSU? If so, why are generator terminal voltages mentioned? 7) We question whether all of the options are required. Many of the system conditions are the same from one application to another. Could the worst case system conditions be presented in paragraph form along with descriptive commentary? 8) SDT should consider including recommendations for the traditional 50/27 elements used for inadvertent energization protection. Traditionally the 50 elements of this type are set near 1.5pu. The setting of the voltage element needs to be evaluated such that it will ride through disturbances but also sense voltage during a true inadvertent energization under worst case system conditions. Perhaps these elements should be considered as specialized forms of 51VC. These elements will also need to comply with PRC-025 LVRT criteria. 9) In reference to Option 17: 150% of the maximum transformer rating can be 250% of the base rating. Transformers are not rated to carry 250% continuously.
No
Implementation should be aligned with other similar standards, such as PRC-024, or even extended based on the number of simulations and relay replacements that will be required.
Group
Operational Compliance
Ed Croft
Yes
As long as Guidelines & Technical Basis is included with the standard, so that the phrase "while maintaining reliable protection" is clarified.
Yes
Yes

We agree with the Implementation Plan of 48 months, but might like to see this time period broken into smaller phases.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Agree
NAGF (North American Generator Forum) In addition to these, we offer the following comments: Question 1: No; 1. It will not always be possible to set load-responsive relays according to Attachment 1 criteria without compromising equipment protection. Where this is the case, the standard must allow for technical exceptions. 2. It should be made clear that entities not using the relay types in Table 1 are by default in compliance with the requirement in R1. 3. Similar to #2 above, if the entity has Device 21 phase distance relays that have load encroachment logic that removes the possibility of tripping on load, the standard should provide an exemption for R1. 4. Measure M1 should be re-written to improve clarity. We suggest, "… each GO shall have: 1) dated documentation of applicable settings calculations, and 2) dated documentation of the settings above having been applied in the field. Question 2: Yes Question 3: No; 1. The criteria for Device 21 on synchronous generators could be greatly simplified by using the criteria in IEEE C37.102, i.e. the 21 setting must be less than or equal to the impedance corresponding to 200% of the generator MVA rating at the rated power factor angle, or a modified version of this to accommodate lower system voltages. 2. The multiple descriptions under "Bus Voltage" (see options 1-3, 5-7, etc) cause this criteria to be difficult to understand and to apply. It is not readily apparent what the different Bus Voltage options are attempting to accomplish. Are options 1 and 2 identical except for the voltage magnitude? It is not clear why a voltage of 0.95 pu is referenced in Option 1 when the Guidelines and Technical Basis section states that the criteria in Table 1 is based on 0.85 pu transmission voltage. Also, the terms "transformer turns ratio and impedance" are not clear as to the intent, and perhaps should be deleted. In the references to "simulation" in options 3, 7, and 15, what specific types of analytical studies are intended here, and what specific generator models are required for them? For these reasons, an approach that is simpler to apply is needed for Table 1. 3. There is a need for a good detailed example calculation for the various options in Table 1. 4. It may be better to break up Table 1 into separate Tables for Generator, GSU's, and Auxiliary Transformers. 5. In Attachment 1, 2nd paragraph: a. Replace "Synchronous generator output pickup setting criteria values " with "Synchronous generator relay setting criteria values" b. We suggest that the setting criteria be based simply on the generator MVA capability and rated power factor, instead of calculating it using the real power rating in MW. 6. Some of the terms may be misunderstood and should be clarified. "Generator Bus" is at the terminals of the generator. Suggest using a term such as "System Bus" or "Transmission Bus" or similar to designate the bus to which the GSU transformer high-side terminals are connected to. Question 4: No; 48 months may be achievable for utility generation, but perhaps not for merchant plans. A timeframe of 72 months is suggested.
Individual
Don Schmit
Nebraska Public Power District
No
1) Table 1, Option 1. "Generator bus voltage corresponding to .95 pu of the high side nominal voltage times the turns ratio of the generator step-up transformer". For example, one of our plants GSU has a high side of 345kv nominal and has a generator nominal voltage of 23kv. Do we assume 345kv/23kv = 15 ratio or do they use the actual ratio which has a tap of 345 and tap of 23.4 = 14.74 ratio. One Generator voltage could be 0.95 x 345 / 15 = 21.85 kv or the Generator voltage could be 0.95 x 345 / 14.74 = 22.24kv. Do we use the Generator bus voltage of 21.85kv, 22.24kv, or is the calculation wrong. If this can be clarified or an example provided this would be helpful. 2) Table 1, Option 1. "The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW. Can you give an example calculation. Our unit is a 757MVA unit. Lets assume our maximum Seasonal gross MW is 650MW. i. Real Power is 650MW ii. Reactive Power is 975MVAR iii. MVA = 1.15 x SQRT (650 x 650 + 975 x 975) = 1348 MVA at 56 degrees. Do we find the impedance of this MVA value at 56 degrees and the 0.95 bus voltage? If this can be clarified or an example provided this would be helpful. The KD 21 relay is a 75 degree relay so how do we account for the power factor of the relay, power factor of load, and power factor from the MVA with your table. Can you give an example calculation? 3)Table 1, Option 10. Can you give an example calculation for option 10. How is an overcurrent affected by voltage? For a 757MVA, 23KV the FLA is 19,002 amps. Can you give an example for setting the 51 relay. Do we calculate the MVA as shown in step 2.iii above then use the 0.85 x (345 / 15) or 0.85 x (345 / 14.74) to obtain the generator voltage so we can calculate the current once the MVA is known. Why are we not selecting 1.5 x FLA. The FLA does not change based on per unit voltage. If this can be clarified or an example provided this would be helpful.

We have seen many interpretations of the calculations for Table 1 during industry forums. Examples need to be provided.
Group
Tennessee Valley Authority
DeWayne Scott
No
Recommend for clarity revising R1 to read: “. . . . . on each load-responsive protective relay (add language: according to its application to maintain) (remove language: while maintaining) reliable protection. . . . . .” If “Rationale for R1” third bullet, term “while maintaining reliable protection” is to be retained, then recommend this term be incorporated into the “Definitions of Terms Used in Standard” on page 2 of 22, of this draft standard package.
No
The Standard Drafting Team needs to revisit this question. Reviewing the PRC-025-1 SAR, Attachment 1, Order No 733 - Action Plan and Timetable, paragraph 102 is not listed as a significant paragraph of Order 733, or for this standard. FERC Order 733, p102, is a comment from Entergy. Reviewing supporting PRC-025-01 background information on the NERC website, there is no reference to FERC Order 733, p102. This question needs to be re-asked with correct FERC Order references.
No
It is not clear if it is required for 1 type (21, 51V, 51C, or 51) to be set according to Table 1 or each type.
No
Recommend a schedule that will coincide with the protective relay requirements stated in the revised NERC, PRC-005-2, Protection System Maintenance standard. The protective relays requirements within PRC-025-1 should coincide with PRC-005 in order to maximize benefit of maintenance to satisfy these two standards and to minimize resources necessary to perform the relay settings calculations and installations required by PRC-025-1, if the relay settings need to be revised from current PRC-005 settings. Recommend both implementation plans should be a minimum of 72 months.
1. There is a strong relationship between this reliability standard, PRC-025-1, Generator Relay Loadability, and PRC-005-2, Protection System Maintenance, regarding the testing, maintenance, and installing the settings on the same protective system relays. To ensure PRC-025 and PRC-005 are in sync with each other, recommend each be referenced in the “F. Associated Documents” of the other. 2. Recommend PRC-025-1 relay settings be recalculated at a frequency that coincides with PRC-005-2, Protection System Maintenance, performance frequencies found in the PRC-005-2, respective tables. The standard should also allow the generator owner to determine for their own applications whether the on-going repetitive calibrations and functional testing should be time based, performance based, or a combination of the two, in accordance with PRC-005-2.
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
No
IMPA recommends using a phased-in Implementation Plan. Generator Owners will have to review current settings and based on this analysis they may have to replace some relays and/or coordinate these relay settings with their Transmission Owner. If relay replacement is required, Generator Owners will have to budget for the new relays. If settings need to be changed, the Generator Owner(s) will need to verify relay settings with the Generator Manufacturer to ensure there are no warranty/safety concerns associated with the relay setting changes. IMPA recommends a 50% completion in 48 months and a 100% completion in 72 months.
Individual
Patrick Brown
Essential Power, LLC

1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot could be cast. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition and how hard it is pushed. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio" under the "Generator Bus Voltage" column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a

worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. 8. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. 9. The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." It should be replaced by the term "generator bus or high side-to-medium voltage," as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. 13. Using the term "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. 14. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection used by many companies has proven (over multiple decades) to be adequate for

protecting equipment and providing reliable power supply to customers.
Individual
Anthony Jablonski
ReliabiltiyFirst
Yes
No
The criteria are much more restrictive than that of the IEEE C37.102 recommendations. As the guide states in regards to a general distance setting of 150 to 200% of the generator MVA rating, "However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." Some of the options for phase distance protection may severely restrict the remote backup protection from the generator. The criteria may prevent the generator backup protection from seeing uncleared faults on the remote ends of lines connected to the plant. It is also not clear whether load encroachment methods would work as referenced in the guidelines since the angle of power flow may be near 60 degrees. Load encroachment at these high angles would cut out most of the reach characteristic and allow little margin for detecting arcing.
Yes
Yes
Individual
Kirit Shah
Ameren
No
(1) As written R1 can be read to require the GO to use load-responsive protective relays. The wording of the first sentence in Attachment 1 is clearer. Please insert "that applies load-responsive protective relays" in R1. "Each Generator Owner that applies load-responsive protective relays shall install settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection." (2) In the Rationale for R1 please insert this as the second sentence in the third paragraph "Equipment protection takes precedence over loadability, but must be clearly justified if the loadability options in Attachment 1 are not met." These generators are quite valuable and have long repair times so their protection must not be compromised. In its generator protection webinars, NERC emphasized that damaging a generator would harm BES reliability more than tripping on load. Though not exactly comparable, it's clear that restoration time is longer when equipment is damaged (e.g. Hurricane Sandy) than from a blackout (e.g. AZ-CA).
No
(1) We have reviewed in detail our own and SERC-wide performance for the last 6 years, and have not had a single generator protection Misoperation because of relay loadability (for Ameren we cannot recall such an operation in the last 30 years.) It appears that the SDT relies too much on the 2003 blackout single event and empirical data for its justification. While we agree it is desirable to protect the generator and meet the loadability objective, protection equipment changes and/or additions are not justified. (2) Please state the total number of generators that tripped in the 2003 blackout to provide proper context. Also, did 2003 blackout post mortem simulations show that had these 28 generators (8 tripped by phase distance and 20 tripped by overcurrent) ridden through the event, the blackout would have been avoided or significantly smaller?
No
(1) The first sentence implies that only "one" of the 17 Options needs to be met. Actually Option 17 almost always must be met as well as one of the first 16 Options. In cases using different relay types for the generator two of the first 16 Options need to be met. (2) Our reading is that the 115% is applied to the loading criteria prior to calculating the impedance or current Pickup Setting Criteria. An example for Options 2 and 5 would provide clarity and help reach your loadability objectives without trapping the GO into unintended non-compliance. (3) Our reading is that Bus Voltage instructions for Option 1 ignore the IZ voltage rise through the GSU but include it for Option 2. Is that the SDT's intention? (4) The last part of p 7 paragraph 2 states the Reactive Power capability is calculated at rated power factor (typically 0.8 to 0.9) which conflicts with the Table 1 Pickup Setting Criteria which uses Reactive Power equal to 150% of rated MW. We suggest to correct this discrepancy. (5) PRC-023 provides a wider range of criteria for meeting transmission loadability. (6) An entity may be forced to reduce the Real Power capability it reports to the Planning Coordinator in order to meet the standard as proposed. This would have an adverse impact on BES reliability.

No
Please allow 60 months to implement if indeed protection system equipment or schemes must be changed to comply with R1. More than 48 months will regularly be needed to budget, design, procure materials, obtain construction outages, install and commission such protection system equipment changes.
Yes. (1) Applicability should be consistent with PRC-023-2 (generators connected at 200kV and above, etc.). (2) System connected auxiliary transformers should be excluded. This is consistent with the industry's determination in PRC-005-2, which has now passed recirculation ballot. (3) VSLs are listed as 'to be determined'. We recommend that severity be risk-based by relating it to the % of MWh the generator in violation has provided during the period of violation (i.e. % of GO entity's total MWh production.)
Group
Bonneville Power Administration
Jamison Dye
Yes
Individual
Don Jones
Texas Reliability Entity
Yes
No
TRE suggests the following changes for Attachment 1: Relay Settings, Table 1: a) On page 7 under 'PRC-025-1-Attachment 1: Relay Settings' discussion of the synchronous generator reactive capability calculations is confusing. TRE suggests the following language for Paragraph 2: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined based on the unit's nameplate megavoltampere (MVA) and the calculated rated MW at the unit's rated power factor." b) In the Table 1. Relay Loadability Evaluation Criteria; recommend specifying 'Synchronous generator bus terminal' instead of 'Synchronous generators' in the application column for Options 1, 2, 3, 5, 6 & 7. c) In the Table 1 - Bus Voltage column, clarify that the generator bus voltage calculation needs to include the generator step-up transformer winding tap setting (NLTC or LTC tap settings) in the turns ratio calculation of the generator step-up transformer, when applicable. Suggested language, "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer. The turns ratio calculation of the step-up transformer must include the transformer's NLTC or LTC tap settings implemented in operation." d) In the Table 1 – Pickup Setting Criteria column, clarify that the rated power factor must be used to calculate the impedance value. Recommend adding the following note under the setting criteria; "Generator rated power factor shall be used to calculate the impedance value". e) In the Table 1 Option 3- Pickup Setting Criteria column, the Reactive Power output determined by the simulation is typically based on the voltage set point at the controlled bus. This can be a moving target if the simulations are done based on different loading conditions. TRE suggests using the generator reactive capability curve (D-Curve) or the actual reactive test data to determine the generator maximum Mvar capability that is to be used for the impedance calculation. f) In the Table 1 -The Phase Time Overcurrent Relay (51V) voltage-restrained option does not provide specific voltage restraint slope settings to be used. For consistency purpose, voltage restraint slope settings should be included in the pickup setting criteria. g) TRE recommends including generic D-curve, R-X diagrams, voltage-restrained relay curve, and other overcurrent, voltage controlled relay curves in this standard to provide additional clarification.
No
TRE thinks that the implementation plan is too long and we suggest 24 months.
Group
Luminant
Brenda Hampton
No

Luminant recommends: 1. The phrase “Each Generator Owner shall install …” be revised “Each Generator Owner shall set …”. The Generator Owner would only be required to show compliance with the documentation of setting calculations and not required to show a recent test report. 2. The corresponding measure would be revised to read, “The Generator owner shall have evidence such as spreadsheets or summaries of calculations to show that each generator load responsive relay is set according to R1.” These recommendations would maintain consistency of requirements and measures with the approach used in PRC-023-2 (Transmission Loadability standard).
No
Luminant agrees that a reasonable approach was used to define limits based on unit MVA ratings for relays susceptible to load. However, the drafting team does not address the coordination of the relay with transmission relaying as described in FERC Order 733, paragraph 107. The Commission directed the ERO to address relay loadability that facilitates the reliability goal of ensuring coordination between transmission and generator protection systems, as required by PRC-001 (draft standard PRC-027). Luminant recommends adding Transmission Owners to the Applicability Section and include relay coordination with the Transmission Owner for each applicable load responsive relay as a separate requirement and measure.
No
1. Luminant agrees that although Table 1 in Attachment 1 clearly identifies criteria for setting load responsive relays, it is recommended that the drafting team add information in the Attachment that describes the bus voltage conditions as steady state values only and does not consider relay operations for fault conditions. In addition, a statement that the Generation Owner must coordinate relays with applicable AVR response and transmission relaying. 2. Luminant recommends the “Pickup Setting Criteria” column for real power output be revised to “100% of maximum seasonal gross or maximum continuous rating of the turbine reported to the Planning Coordinator”. 3. In Row 17 (Auxiliary Transformers - Phase Overcurrent Relay), Luminant recommends that the 150% pickup setting criteria be applicable to the relay regardless of its electrical location (high or low side of the UAT).
Yes

Consideration of Comments

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation (PRC-025-1)

The Project 2010-13.2 Drafting Team thanks all commenters who submitted comments on the proposed standard, PRC-025-1 which was posted for a 30-day formal comment period from October 5, 2012 through November 5, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 39 sets of comments, including comments from approximately 112 different people from approximately 90 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Summary Consideration

In the previous initial posting and first formal comment period, the standard received valuable comments. The Generator Relay Loadability Standard Drafting Team ("drafting team") made significant improvements to the standard based on these comments. The drafting team believes it has addressed stakeholder comments and concerns in such a way that the standard is improved and meets the expectations expressed in comments for reliability and industry approval.

Majority comments revealed a number of common concerns which resulted in changes to the main body of the standard. Concerns and summary changes include: The word "install" in Requirement R1 is not an industry standard word – the word "install" was replaced with "apply" and Measure M1 was changed to comport with R1, the phrase "while maintaining reliable protection" was updated by inserting the word "fault" to make the phrase "while maintaining reliable fault protection," the Measure M1 was revised to remove the appearance of adding to the requirement by listing the evidences as examples, potential overlap with the current PRC-023-2 – Transmission Relay Loadability Reliability Standard is being addressed through a proposed revision outlined in the posted supplemental Standards Authorization Request (SAR), and a more understandable structure of Table 1 was created for clarity.

Majority comments revealed a number of common concerns which did not result in changes to the main body of the standard. Concerns and summary responses include: The concept of "identify, assess, and correct," was not implemented as it is not practical for this type standard, flexibility in setting relays is not needed because the standard already provides a number of multiple options (e.g., a simple calculation, a more complex and precise calculation, or the most precise method using simulation), and Measure M1 does not need to include a provision for entities that are already compliant because the implementation plan allows sufficient time for entities to document compliance.

Minority comments revealed a number of independent concerns which resulted in changes to the main body of the standard. Concerns and summary changes include: The standard does not pertain to protective functions for conditions such as inadvertent energization, or flashover schemes – exceptions have been included in Attachment 1: Relay Settings, applicable load-responsive protective relays based on connection or configuration was not clear – the standard now clarifies this by describing the appropriate terminals, confusion about using the seasonal output capability - resolved by removing the word "seasonal" to be consistent with the proposed MOD-025-2, and protective relay nomenclature (i.e., 51C and 51R) is not consistent with industry - updated to 51V-R and 51V-C for greater clarity and consistency.

Minority comments revealed a number of independent concerns which did not result in changes to the main body of the standard. Concerns and summary responses include: The standard does requires an entity to install load-responsive protective relays – the standard only applies to the those Facilities in the "Applicability" section, the out-of-step protective relays, exciter power potential transformers (PPT), and isolated phase bus (IPB) were not included in the applicability – to comport with the scope of the project they were not included in the applicability, PRC-025-1 may conflict with standards PRC-019 and MOD-024 – these standards relate to AVR protection and Real Power modeling (respectively), the standard appears to encourage Generator Owners to exceed the manufacturer's rating of equipment – the standard does not represent an intentional operating point, standard did not include provisions for a light load condition (i.e., 40%) – this condition was considered and found not to have a reliability benefit in the standard, the standard should mirror PRC-023-2 – Transmission Relay Loadability – transmission loadability responds to a wide variety of topologies affect the loadability resulting in many different criteria and is not a practical fit for PRC-025-1, the standard requires entities to perform modifications to their protective relays or protection philosophies to achieve the required protection to satisfy this standard – the standard may require entities to address new technologies or philosophy changes to comply, and entities desired having an RSAW to compare for auditing – the drafting team provided input to NERC Compliance in the development of the PRC-025-1 RSAW and it may be viewed under the Compliance area of the NERC website.

Comments revealed a number of common concerns which resulted in changes to the Guidelines and Technical Basis. Concerns and summary changes include: The standard lacks clarity about the duration to which the standard applies to "adequately protect its equipment" for fault conditions – clarifying text was added, there is a lack of clarity about the duration to which the standard applies for overload conditions – clarifying text was added, the standard needs examples that illustrate the calculations needed to derive impedance and overcurrent values – extensive example calculations have been added for clarity.

Now that the standard has received formal industry input and standard drafting team modifications, the standard will advance to its second formal comment period which will include an initial ballot to be conducted in the last ten days of the comment period.

Purpose: The Purpose statement was revised to better reflect the intent of the standard based on industry comment.

Applicability: The Applicability section was revised to clarify the Facilities to which the standard is applicable. The drafting team made a clarifying change in section 3.1.1 to eliminate potential overlap with the standard, PRC-023-2.[1] The phrase "at the terminals of" was applied to the proposed PRC-023-3 standard in the Applicability section. Using this phrase demarcates the applicability by identifying the location of the load-responsive relay. To conform the draft 2 of PRC-025-1 with the proposed PRC-023-3 revision, the standard drafting team "3.2.4 Generator interconnection Facility(ies)" to the Applicability. This addresses conditions where generation Facility ownership may not be typical of the industry to comport with PRC-023-3 revision and to avoid a potential gap between the two standards.

Effective Date: No change. See the implementation plan for the proposed two-phased approach.

Requirement: The drafting team made a minor change to Requirement R1 to address several comments. The word "install" was replaced with "apply" to be more consistent with industry terminology and usage.

Measures: The Measure M1 was revised to comport with the revision to Requirement R1. This measure was further edited to remove the appearance that the measure was requiring additional performance over and above the performance of Requirement R1 by listing the evidence as examples.

Compliance Monitoring Process: Typographical correction.

Violation Severity Levels: The drafting team has provided a single VSL for Requirement R1, the only requirement in the standard. The posted Violation Risk Factors and Violation Severity Levels Justification document describe how the standard drafting team's proposed VRFs and VSLs comply with the current guidelines for constructing VRFs and VSLs.

Attachment 1: Relay Settings: The drafting team made clarifying improvements to the introductory section of the attachment. Additional information was appended concerning no-load tap changers (NLTC) and on-load (OLTC) tap changers and relay elements that are excluded from the standard. Additionally, exclusions for certain application of load-responsive protective relay elements and the conditions to which the exclusions apply.

Table 1: Relay Loadability Evaluation Criteria: The drafting team made substantial improvements to Table 1 based on industry stakeholder comment. Table 1 has been restructured such that the first

[1] The drafting team has posted a supplemental Standard Authorization Request to make conforming revisions to PRC-023-2 – Transmission Relay Loadability to eliminate potential overlap between the proposed PRC-025-1 standard.

column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers (UAT), and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column now identifies each load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, and 67) according to its application listed in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars may be blank or contain information text to bring awareness to the reader to information on a following page.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for a given application has one or more options (i.e., "ways") to determine the bus voltage and associated pickup setting criteria. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

Table 1 is further formatted by alternately shading groups of relays within a similar application to aid reader awareness. Also, intentional buffers were added to the table so that similar options would be paired together on a per page basis. These buffers may be blank or contain information text to bring awareness to the reader to information a following page. Note that some applications may have additional pairing that might occur on adjacent pages.

Guidelines and Technical Basis: Overall, this section was rewritten to parallel the new structure of Table 1 and has been separated into its own document for manageability. Comments revealed that conditions may exist where a Generator Owner might apply a phase directional time overcurrent relay (67) – directional toward the Transmission system. Given this possibility, the drafting team concluded this relay function should be included in the standard to eliminate a gap and avoid confusion with this type load-responsive protective relay.

The following is provided to illustrate the reorganization to Table 1.[2]

Application	Relay Type	Draft 1 Option	Draft 2 Option
Synchronous Generators	Phase distance relay (21) – directional toward the	1	1a

[2] The drafting team inserted the new Table 1 structure in the "redline to draft 1" in order to present the textual changes to the options and avoid the issues with demonstrating the redline changes of a table. Note that the redline to draft 1 may give the appearance, for some options, that the cross-reference of the options listed here may not be correct. This is due to the application's creation of the redline; therefore, use this table cross-reference to review how the options were revised.

Application	Relay Type	Draft 1 Option	Draft 2 Option
	Transmission system	2	1b
		3	1c
	Phase time overcurrent relay (51V-R) – voltage-restrained	5	2a
		6	2b
		7	2c
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	9	3
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	4
	Phase time overcurrent relay (51V-R) – voltage-restrained	8	5
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	-	6
Generator step-up transformer – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	13	7a
		14	7b
		15	7c
	Phase time overcurrent relay (51)	-	8a
		10	8b
		11	8c
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	9a
		-	9b
		-	9c
Generator step-up transformer – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	16	10
	Phase time overcurrent relay (51)	12	11a
		-	11b
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	12
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51)	17	13a
		-	13b
Generator interconnection Facilities – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	-	14a
		-	14b
	Phase time overcurrent relay (51)	-	15a
		-	15b
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	16a
		-	16b

Application	Relay Type	Draft 1 Option	Draft 2 Option
Generator interconnection Facilities – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	-	17
	Phase time overcurrent relay (51)	-	18
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	19

Example calculations were also added to the Guidelines and Technical Basis as requested by a number of commenters.

Implementation Plan: The implementation plan was revised to provide additional information about the considerations made by the drafting team. More importantly, the drafting team revised the implementation plan to provide industry a two-phase approach to implementing the standard. As proposed, entities will have 48 months to apply settings and become 100%compliant on existing load-responsive protective relays or, where equipment requires replacement, 72 months (two additional years) to replace equipment with the required settings and become 100% compliant.

VRFs and VSLs: The drafting team developed and has provided the VRF and VSL justifications based on FERC and NERC guidelines for industry review.

Additional Information

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[3]

Index to Questions, Comments, and Responses

[3] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Domionion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
25.	Christina Koncz	PSEG Power LLC	NPCC	5

2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Ron McIvor	OPPD	MRO	1, 3, 5
4.	Valerie Pinamonti	AEP	SPP	1, 3, 5
5.	Mahmood Safi	OPPD	MRO	1, 3, 5
6.	Joe Border	MsPhearson Board of public utilities	SPP	1, 3, 5
7.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6

3.	Group	David Thorne	Pepco Holdings Inc. & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Llight	RFC	1
2.	Alvan Depew	Pepco Holdings	RFC	1

4.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Clem Cassmeyer	Western Farmers Electric Cooperative	ERCOT	1, 5
3.	Tom Alban	Buckeye Power, Inc.	RFC	3, 4
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	SERC	1
5.	Susan Sosbe	Wabash Valley Power Association	RFC	3
6.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5

5.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Szulczewski		RFC	3, 4, 5

6.	Group	Will Smith	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD DAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Mike Garton	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2. Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3. Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Fran Halpin	Duty Scheduling	WECC	5
2. Dean Bender	SPC Technical Svcs	WECC	1
3. Stephen Enyeart	Customer Service Engineering	WECC	1

				1	2	3	4	5	6	7	8	9	10
10.	Group	Brenda Hampton	Luminant						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Laney	Luminant Generation Company LLC	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
11.	Stephen	Berger	PPL Generation, LLC	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2. Brent Ingebrigston	LG&E and KU Services	SERC	3

		Company		
3.	Annette M. Bannon	PPL Generation, LLC	RFC	5
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
13.	Individual	Jim Watson	Dynegy, Inc.					X					
14.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
15.	Individual	ryan millard	pacificorp	X		X		X	X				
16.	Individual	Shammara Hasty	Southern Company (Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation Energy Market)	X		X		X	X				
17.	Individual	Ed Croft	Operational Compliance	X		X		X					
18.	Individual	DeWayne Scott	Tennessee Valley Authority	X		X		X	X				
19.	Individual	Jeffrey Streifling	ATCO Power										
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Michael Falvo	Independent Electricity System Operator		X								
22.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
23.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
24.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
25.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
26.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
27.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
28.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
29.	Individual	Timothy Brown	Idaho Power Company	X		X							
30.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
32.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
33.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
34.	Individual	Patrick Brown	Essential Power, LLC					X					
35.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
36.	Individual	Kirit Shah	Ameren	X		X		X	X				
37.	Individual	Don Jones	Texas Reliability Entity										X
38.	Individual	Maggy Powell	Exelon Corporation and it’s affiliates	X		X	X	X	X				
39.	Individual	Patrick Brown	North American Generator Forum										

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Two entities submitted comments in support of those comments submitted by the North American Generator Forum (NAGF) industry trade association. One entity, Wisconsin Electric Power Company, provided additional comments for questions 1, 3, and 4; responses to these comments are found in their respective questions. Two additional entities (Essential Power, LLC and PPL and Affiliates) submitted the same or near same comments as the NAGF under the comment questions 1, 2, 3, 4, and 5 rather than affirming their support in this section.

Organization	Supporting Comments of "Entity Name"
Dynegy, Inc.	North American Generator Forum
Wisconsin Electric Power Company	NAGF (North American Generator Forum) In addition to these, we offer the following comments: **Response:** Other comments are found under the corresponding questions below.
Response: Thank you for your comments, please see the responses provided below for the NAGF industry trade association found in question #5.	

1. **Is the performance of Requirement R1 (and Measure M1) clear that the Generator Owner must determine and install settings on its load-responsive protective relays in accordance with <u>PRC-025-1 – Attachment 1: Relay Settings</u>? If not, provide specific suggestions to improve or clarify the performance.**

Summary Consideration:

Approximately 18 commenters representing about 61 entities provided comments for question #1. Fourteen common themes were revealed by commenters; of those, about half represent majority opinions by comment count and entities represented.

The first two majority comment themes did not result in any substantial change.

(1) Six comments supported by at least 12 entities were concerning an entity being able to "adequately" protect its equipment under the requirements anticipated by the standard. The drafting team responded that entities must still "adequately" protect their equipment with regard to faults; however, an entity may need to perform modifications to its protective relays or protection philosophies in order to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the standard provides suitable options to address the concern and the drafting team has developed the implementation plan to accommodate an entity that may need to perform modifications to its protective relays or protection system philosophies to achieve compliance with the standard and reliable fault protection.

(2) Three comments from at least nine entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as "field-forcing" which is a loadability issue, not an overload condition. This duration of which is within the thermal overload limits raised by the comments.

The next three majority comment themes resulted in changes to the standard.

(3) Four comments from at least six entities were concerned about the word "install" in Requirement R1. The drafting team addressed this concern by replacing "install" with "apply" to be more consistent with industry terminology.

(4) The drafting team received two comments supported by at least nine entities to consider developing a Reliability Standard Audit Worksheet (RSAW) document contemporaneously with the development of the standard. This idea was embraced and the drafting team provided NERC Compliance with valuable input into a draft RSAW for posting on the NERC website (www.nerc.com) under the Compliance tab. Entities following the development of PRC-025-1 may review the posted draft RSAW and provide feedback. Development of the RSAW is not a part of the standard development process and feedback should be provided through the RSAW feedback form to NERC Compliance.

(5) About three comments also supported by at least six entities were concerned about the phrase “while maintaining reliable protection” in Requirement R1. The drafting team addressed this concern through a minor change, by inserting the word “fault” to make the phrase “while maintaining reliable fault protection.” The standard is conveying that entities must install settings for loadability for the conditions found in Attachment 1 (e.g., depressed voltages) and must also provide the necessary (i.e., reliable) fault protection for equipment.

The next three comment themes did not result in changes to the standard.

(6) Two comments supported by at least nine entities were received which suggested restructuring the standard using the concept of “identify, assess, and correct” as utilized by some of the recent Critical Infrastructure Protection (CIP) version five standards. The drafting considered this approach; however, determined that it was not a good fit considering settings on generation facilities are not systematically revisited unless a major change occurs to the generation unit or associated equipment.

(7) Two comments also supported by at least nine entities requested greater flexibility in setting their load-responsive protective relays. The drafting team responded that the standard by the use of “Options” has provided this flexibility. To determine settings, an entity may select a simple calculation, a more complex and precise calculation, or the most precise method using simulation. Additionally, the standard provides each entity the ability to set its load-responsive protective relays more stringent than the values required by the Table 1 in Attachment 1.

(8) The last majority single comment supported by at least 17 entities expressed concern that no consideration in Measure M1 was given to entities that may already be compliant with the standard. The drafting team did not make any changes, but notes that the implementation provides an adequate duration for an entity to document their compliance for audit purposes.

The next two of six minority comment themes resulted in a change to the standard.

(9) One comment supported by at least two entities was concerned that the standard may also apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(10) One comment also supported by at least eight entities was concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

The last four minority comment themes did not result in a change to the standard.

(11) Two comments supported by at least two entities concerned the applicability of load-responsive protective relays requiring an entity to install relays. The drafting team clarified in the document that only those load-responsive protective relays as identified by the Applicability section of the standard are applicable and the standard and does not require entities to install such relays.

(12) One comment supported by at least eight entities was concerned about the potential overlap between the PRC-024-1 currently under development and the draft PRC-025-1 standard. The drafting team previously identified this issue and coordinated with the PRC-024-1 drafting team to have the load-responsive protective relay references removed from the PRC-024-1 footnote to provide greater distinction between the standards.

(13) One comment supported by at least two entities suggested that load-responsive protective relays protecting exciter power potential transformers (PPT) and isolated phase bus (IPB) or commonly referred to as ISO Phase Bus should be applicable to the standard. The drafting team did not include this equipment as it was outside the scope of the project's SAR.

(14) One comment provided by a single entity raised concern that PRC-025-1 maybe in conflict with standards PRC-019 and MOD-024. The drafting team reviewed these standards and determined that PRC-019 pertains to coordination of applicable protective functions regarding automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict. The standard MOD-024 addresses the reported output capability a Generator Owner would use in determining its settings under PRC-025-1 and also has no observed conflict.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1) As written R1 can be read to require the GO to use load-responsive protective relays. The wording of the first sentence in Attachment 1 is clearer. Please insert "that applies load-responsive protective relays" in R1. "Each Generator Owner that applies load-responsive protective relays shall install settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection." **Response:** The drafting team believes adding the additional "that applies…" within Requirement R1 is duplicative and unnecessary. The Applicability 3.1.1 section clearly identifies the standard and requirement that is applicable to load-responsive protective relays applied by the

Organization	Yes or No	Question 1 Comment
		Generator Owner. For example section 3.1.1 states, "Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities." No change made. (2) In the Rationale for R1 please insert this as the second sentence in the third paragraph "Equipment protection takes precedence over loadability, but must be clearly justified if the loadability options in Attachment 1 are not met." These generators are quite valuable and have long repair times so their protection must not be compromised. In its generator protection webinars, NERC emphasized that damaging a generator would harm BES reliability more than tripping on load. Though not exactly comparable, it's clear that restoration time is longer when equipment is damaged (e.g. Hurricane Sandy) than from a blackout (e.g. AZ-CA). **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable <u>fault</u> protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. The drafting team intends that this phrase emphasize that entities must

Organization	Yes or No	Question 1 Comment
		still “adequately” protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) There is potential for double jeopardy with PRC-025-1 and PRC-023-2. PRC-023-2 also applies to relays on GSU transformers under 100kV. Collectively, applicability section 4.2.1.6 and Attachment A, 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that “forms a path.” With this proposed standard, a GO/GOP could be found in violation of both PRC-023-2 and PRC-025-1 for not having appropriate relay loadability settings. We strongly suggest that the SDT consider revising PRC-023-2 to remove all references to Generators in order to avoid any possible instances of double jeopardy. This would be consistent with FERC Order 733, paragraph 106, “we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability.” If generator loadability is going to be addressed in its own standard, then it should not overlap with transmission relay loadability and PRC-023.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls and elimination of zero-defect expectations). To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. As an example, what happens if a GO miscalculates their setting or inadvertently uses the wrong setting for one unit? This should not be a violation, per se, if the GO discovers it and corrects it. **Response:** The drafting team considered alternatives such as the “identify, assess, and correct concepts for the proposed PRC-025-1 standard. The drafting team concurred that this standard does not lend itself to this concept because most Generator Owners would not have circumstances that would necessitate the entity to periodically revisit the setting once applied on its load-responsive protective relays. Also, the drafting team believes that the PRC-004 mis-operations standard work will provide an acceptable approach to identify miscalculations. No change made. The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website. (3) We are concerned that this standard also duplicates the proposed PRC-

Organization	Yes or No	Question 1 Comment
		024-1 of Project 2007-09 Generator Verification. Proposed PRC-024-1 requires a GO to ensure its voltage protective relaying does not trip as a result of a voltage excursion. Does the voltage control relaying include Phase-Time Overcurrent Relay (51V) voltage-restrained from Table 1 in Attachment 1 of proposed PRC-025-1? Is the 0.85 pu voltage identified in the same table not a voltage excursion? If so, this duplication needs to be eliminated. **Response:** The drafting team recognized the duplication and coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that the load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made. (4) The standard needs some clear flexibility built into it to deviate from the settings in Attachment 1. Consider an example where a GO sets its phase distance relay on its synchronous generator to meet option 1 and an event causes the unit to trip anyway. The GO should be allowed to reassess and apply an appropriate setting even it if deviates from the Attachment 1 relay settings. **Response:** The drafting team notes that the Requirement R1 does not preclude the Generator Owner from setting its load-responsive protective relays at a more conservative margin than what is required by Attachment 1: Relay Settings. The attachment in the "Pickup Setting Criteria" column or Table 1: Relay Loadability Evaluation Criteria uses phrases such as "shall be set less than" and "shall be set greater than" to accomplish flexibility. No change made.
Response: Thank you for your comments, please see the responses provided above.		

Organization	Yes or No	Question 1 Comment
Duke Energy	No	1) R1 states that protection must meet the criteria and be reliable - this is not possible. Protection is often considered an artform, since it includes making compromising decisions between dependability and security. This standard, by its nature, is biased toward security. It requires relays to be set such that they can no longer be depended upon to prevent potential damaging operating conditions. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability.

Organization	Yes or No	Question 1 Comment
		For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. 2) In its current form, this standard seems to disregard the factor of time, as it relates to equipment withstand for the specified system conditions. For example, Table 1 will require 51T relays on the GSU not to pickup before 2.2pu (for a machine rated .9pf), even though the transformer through-fault protection curve of IEEE C57.12 does not support continuous operation at that point and the generator stator thermal limit, per IEEE C50.13, is less than 10 seconds. Requiring the GO to permit operation of equipment outside American national equipment standards is incongruent with improving the reliability of the BES. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable <u>fault</u> protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT

Organization	Yes or No	Question 1 Comment
		effective during stressed system conditions. The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards. Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made. 3) In section M1 on pp4/22: reword to "(2) Record Settings" Response: The drafting team has modified the Measure M1 in consideration of your comment and others. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Independent Electricity System Operator	No	a. Requirement R1 seems clear but replacing the word “install” with “implement” or “determine” would seem more appropriate that the settings are not exactly “installed”. If the SDT accepts this proposed change, then conforming changes need to be made to M1 and throughout the entire standard. **Response:** The drafting team has modified the standard to “apply”

Organization	Yes or No	Question 1 Comment
		settings instead of "install" settings. Change made. a. The language in M1 seems unclear to convey the evidence needed to be provided to demonstrate compliance with R1. We suggest M1 be revised to: For each load-responsive protective relay, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed (suggest to replace it with determined or implemented) in accordance with PRC-025-1 - Attachment 1: Relay Settings. **Response:** The drafting team has modified the Measure M1 in consideration of your comment and others. Change made.
Response: Thank you for your comments, please see the responses provided above.		
South Carolina Electric and Gas	No	Entities may have situations where appropriate equipment protection cannot be met and accommodate the load-responsive requirements of Attachment 1. For these rare cases there should be some provision established to allow the Entities to maintain compliance. **Response: The drafting team intends that this phrase emphasize that** entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed

Organization	Yes or No	Question 1 Comment
		on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. The wording of R1 should be changed to clarify that the relay settings applied to load responsive relays must meet or exceed the requirements in Attachment 1. The present wording could be interpreted to require that the load responsive relay settings must be set exactly as prescribed in Attachment 1. **Response:** The drafting team notes that the Requirement R1 does not preclude the Generator Owner from setting its load-responsive protective relays at a more conservative margin than what is required by Attachment 1: Relay Settings. The attachment in the “Pickup Setting Criteria” column or Table 1: Relay Loadability Evaluation Criteria uses phrases such as “shall be set less than” and “shall be set greater than” to accomplish flexibility. No change made.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments, please see the responses provided above.		
Luminant	No	Luminant recommends: 1. The phrase "Each Generator Owner shall install ..." be revised "Each Generator Owner shall set ...". The Generator Owner would only be required to show compliance with the documentation of setting calculations and not required to show a recent test report. **Response:** The drafting team has modified the standard to "apply" settings instead of "install" settings. Change made. 2. The corresponding measure would be revised to read, "The Generator owner shall have evidence such as spreadsheets or summaries of calculations to show that each generator load responsive relay is set according to R1." These recommendations would maintain consistency of requirements and measures with the approach used in PRC-023-2 (Transmission Loadability standard). **Response:** The drafting team has modified the Measure M1 in consideration of your comment and others. Change made. The drafting team considered the application of the suggestion '1' above with respect to '2' for Measure M1. The drafting team considers the suggestion more restrictive.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	Recommend for clarity revising R1 to read: ". . . . . on each load-responsive protective relay (add language: according to its application to maintain) (remove language: while maintaining) reliable protection. . . . . ." If "Rationale for R1" third bullet, term "while maintaining reliable protection" is to be retained, then recommend this term be incorporated

Organization	Yes or No	Question 1 Comment
		into the "Definitions of Terms Used in Standard" on page 2 of 22, of this draft standard package. **Response:** The drafting team has added the word "fault" in the phrase "while maintaining reliable [fault] protection" in Requirement R1. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Pepco Holdings Inc. & Affiliates	No	Requirement R1 and the wording in Attachment 1 require the GO to install settings on "each load responsive protective relay" in accordance with Attachment 1, Table 1. The standard should make it clear that it does not apply to any load responsive relay (i.e., phase overcurrent protection) that is armed only when the generator is disconnected from the system, or enabled only during generator start-up (i.e., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, open breaker flashover schemes, etc.). Nor should it apply to any phase fault detector relays employed to supervise phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) providing the distance element is set in accordance with the criteria outlined in the standard.
Response: The drafting team thanks you for your comment and notes that the application of load-responsive protective relays applicable to the standard only apply while the generator is online. Relays that are armed when the generator is disconnected from the system, enabled during start-up, used for inadvertent energization schemes, open breaker flashover schemes, or and phase fault detector relays are not applicable to the standard. Attachment 1: Relay Settings has been revised to clarify when the load-responsive protective relays are applicable to the standard. Change made.		
Detroit Edison	No	The intent of the requirement is clear, but the specifics of how to accomplish it are not. **Response:** The drafting team is unable to respond absent additional

Organization	Yes or No	Question 1 Comment
		information concerning how to accomplish the requirement. No change made. Not sure of the meaning of "performance" in this context. **Response:** The drafting team adds that "performance," as used in the comment form question, describes what the Generator Owner actually does to achieve the goal or purpose of the standard. In this case, the "performance" is determining the margins to be used on each load-responsive protective relay according to the application options listed in the Attachment 1, Table 1. No change made.
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	The NSRF is concerned that Measure M1 does not take into consideration situations in which existing relay settings are already in compliance with the standard but the setting calculations are not dated and/or the actual date that the settings were installed is not known. To better align with the risk-based requirement, the NSRF recommends M1 be revised to only require evidence showing that the relays settings were in compliance prior to the enforcement date. M1. For each load-responsive protective relay in accordance with PRC-025-1 - Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed in compliance with Requirement R1.
Response: The drafting team thanks you for your comment and understands that there might be cases where load-responsive protective relays already meet the standard and that specific evidence of compliance may not be readily available; however, the standard's implementation plan provides ample time for each Generator Owner to assess and document its compliance with the standard. Measure M1 has been modified based on other commenters suggestions.		

Organization	Yes or No	Question 1 Comment
For clarity and other commenters, the drafting team has provided the suggested change to Measure M1 in redline form below for reference only. Note, the only change observed was the additional text colored blue and underline (i.e., "…in compliance with Requirement R1). *M1. For each load-responsive protective relay in accordance with PRC-025-1 - Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed <u>in compliance with Requirement R1</u>.*		
Entergy Services, Inc. (Transmission)	No	The objectives of the following NERC Standards closely match the objectives of the proposed standard, MOD-024, MOD-025(pending regulatory approval) and PRC-019 (Standard under development). Entergy is currently validating the maximum generator capability under SERC criteria for MOD-024 and MOD-025. This validation requires coordination with applicable load responsive relays.
Response: The drafting team thanks you for your comment and notes that the cited standards referenced operating capabilities and PRC-025 addresses short-term disturbances and that the objectives are not as similar as suggested to be. The MOD standards are dealing with steady state capability. The standard PRC-019 is focused on coordination between AVR control and associated protection setting. The objective in PRC-025-1 is to ensure the field forcing capability of the machine is used to allow the machine to stay on-line for a recoverable system disturbance. No change made.		
Southern Company	No	The requirement is clear - the protective relay setting specifications are not acceptable. We believe that using "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. **Response:** The drafting team has modified the standard to "apply" settings instead of "install" settings. Change made. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the

Organization	Yes or No	Question 1 Comment
		Guideline and Technical Basis section, may not be compatible with "achieving ...desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, our desired protection level is more conservative so that generation equipment is not allowed to be operated in overloaded conditions. Our experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specificed in Table 1 and not result in undesirable nuisance tripping. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES

Organization	Yes or No	Question 1 Comment
		reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.		
New York Power Authority	No	There was no mention of load responsive relays on an Exciter PPT which is connected to the terminal side of the Generator. There was also no mention of any load responsive relays connected to the ISO Phase Bus between the Generator and the Unit Auxiliary Transformer or the secondary side of the Unit Aux Transformer.
Response: The drafting team notes that the concerns raised relative to relays on an Exciter Power Potential Transformer (PPT) and Isolated Phase Bus (i.e., ISO Phase Bus or IPB) between the generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up transformer, and auxiliary unit transformers (UAT) are within the scope of the standard. No change made.		
PPL and Affiliates	No	Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard.
Response: The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made.		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	No	1. It will not always be possible to set load-responsive relays according to Attachment 1 criteria without compromising equipment protection. Where this is the case, the standard must allow for technical exceptions. **Response:** The drafting team notes that the entity is expected to provide necessary protection while meeting the requirements of this standard. If legacy approaches do not allow the entity to meet both, other approaches may be necessary. Options have been added to the unit auxiliary transformer (UAT) criteria to allow calculations based on the actual connected auxiliary bus loads and to allow for auxiliary bus performance simulations. For other elements addressed, options have already been provided for the entity to base the protective relay settings on simulated performance. Change made. 2. It should be made clear that entities not using the relay types in Table 1 are by default in compliance with the requirement in R1. **Response:** The drafting team notes that the phrase in Applicability 3.1.1 “that applies load-responsive protective relays…” and at the beginning of Attachment 1, “Each Generator Owner that applies load-responsive protective relays shall use one of the following Options 1-19…” (emphasis added) address your concern by emphasizing that only those relays being applied by the entity are addressed by this standard. No change made. 3. Similar to #2 above, if the entity has Device 21 phase distance relays that have load encroachment logic that removes the possibility of tripping on load, the standard should provide an exemption for R1. **Response:** The drafting team notes that load encroachment logic by itself does not relieve an entity from having to comply with the requirement of this standard. It may, however be useful in attaining the necessary load-responsive protective relay loadability. No change made. 4. Measure M1 should be re-written to improve clarity. We suggest, “…

Organization	Yes or No	Question 1 Comment
		each GO shall have: 1) dated documentation of applicable settings calculations, and 2) dated documentation of the settings above having been applied in the field. **Response:** The drafting team revised the measure to "applied" rather "installed". Otherwise, the drafting team sees no benefit in further modifying the measure as suggested. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Manitoba Hydro	Yes	(1) It is not clear what this question means by the "performance of Requirement R1". If it means that Requirement R1 (and Measure M1) is clear, then yes it is. **Response:** The drafting team adds that "performance," as used in the comment form question, describes what the Generator Owner actually does to achieve the goal or purpose of the standard. In this case, the "performance" is determining the margins to be used on each load-responsive protective relay according to the application options listed in the Attachment 1, Table 1. No change made. (2) R1: The phrase 'while maintaining reliable protection' is extremely ambiguous. We noted that in the rationale, the reader is referred to the Guidelines for elaboration on this phrase. The discussion in the Guideline did little to clarify in our opinion; it discusses balancing the standard and the entity's desired protection plan. Is the standard not mandatory and the entity's overall plan for reliability and protection needs to incorporate the satisfaction of this standard (and others)? **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this

Organization	Yes or No	Question 1 Comment
		standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. (3) M1: The measure as drafted fails to address whether the entity missed installing relays that are required by Attachment A, it is only looking for evidence specifically related to those relays that were installed in accordance with Attachment A. **Response:** The drafting team clarifies that Requirement R1 does not require a Generator Owner to install load-responsive protective relays. The requirement is to install settings in accordance with Attachment 1 where the Generator Owner has applied load-responsive protective relays on its Facilities. Refer to the Applicability section of the standard for additional detail. No change made.
Response: Thank you for your support and comments, please see the responses provided above.		
Operational Compliance	Yes	As long as Guidelines & Technical Basis is included with the standard, so that the phrase "while maintaining reliable protection" is clarified.
Response: The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system		

Organization	Yes or No	Question 1 Comment
operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP ("ICLP") agrees that the instruction is clear in both R1 and M1, but does not agree that the language meets the intent of a "risk-based requirement." The concept, as we understand it, is to focus on the quality of the process which manages the implementation of the settings - not a confirmation that the settings are always perfectly compliant. There is no risk at all inherent in R1, excluding that to the unfortunate Generator Owner who happens to miss-set a single relay. We suggest a preface to R1 similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". This will allow some flexibility when a rare error takes place - while accounting for those entities whose internal controls are not sufficient to the task. In addition, the language addresses those situations where a NERC-compliant setting is not possible without placing equipment or safety at risk.
Response: The drafting team considered alternatives such as the "identify, assess, and correct concepts for the proposed PRC-025-1 standard. The drafting team concurred that this standard does not lend itself to this concept because most Generator Owners would not have circumstances that would necessitate the entity to periodically revisit the setting once applied on its load-responsive protective relays. Also, the drafting team believes that the PRC-004 mis-operations standard work will provide an acceptable approach to identify miscalculations. No change made.		

Organization	Yes or No	Question 1 Comment
The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website.		
Los Angeles Department of Water and Power	Yes	It is clear the Generator must determine and install settings on its load-responsive protective relays in accordance with PRC-025-1.
Response: The drafting team thanks you for your support and comment. No change made.		
ATCO Power	Yes	The requirement is clear enough -- the ambiguities arise in the attachment.
Response: The drafting team thanks you for your support and comment. While no suggestions for improvement were offered the drafting team has restructured Table 1 in an effort to make it clearer. No change made.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
Indiana Municipal Power Agency	Yes	
ReliabiltiyFirst	Yes	
Texas Reliability Entity	Yes	

2. **In response to FERC Order No. 733, paragraph 102, does the Technical Basis and Guidelines provide adequate rationale for the criteria in <u>PRC-025-1 – Attachment 1: Relay Settings</u>? If not, provide additional detail that would improve the rationale for setting load-responsive protective relays.**

Summary Consideration:

The drafting team notes that the FERC Order No. 733, paragraph 102, reference should have been paragraph "108." The drafting team apologizes for this error. For reference the paragraph reads:

108. Finally, the PSEG Companies suggest that the ERO consider whether a ***generic rating percentage can be established for generator step-up transformers*** *and, if so, determine that percentage. Although we [i.e., Commission] do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.*

Approximately 17 commenters representing about 61 entities provided comments for question #2. Ten common themes were revealed by commenters, of those, four represent the majority opinions by comment count and entities represented.

These first two majority comment themes did not result in change to the standard.

(1) Four comments supported by at least 22 entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as "field-forcing" which is a loadability issue, not an overload condition. This duration is within the generator field thermal overload limits raised by these comments. Additionally, there were concerns about why IEEE C37.102 is not adequate and the necessity of the standard. The drafting team contends that IEEE C37.102 represents general protection and that the standard is addressing protection criteria in greater specificity, as well as a regulatory directive related to concerns identified following the August 14, 2003 Northeast blackout.

(2) Approximately three comments supported by at least 25 entities were concerned about the phrase "while maintaining reliable protection" in Requirement R1. The drafting team addressed this through a minor change by inserting the word "fault" to make the phrase "while maintaining reliable fault protection." The standard is conveying that entities must install settings for loadability for the conditions found in Attachment 1 (e.g., depressed voltages) and must also provide the necessary (i.e., reliable) fault protection for equipment. Other similar concerns included the necessity to replace load-responsive protective relays to become compliant with the standard. The drafting team responded to these comments that entities must still "adequately" protect their equipment with regard to faults. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the

standard provides suitable options to address the issue and the drafting team has developed the implementation plan to accommodate an entity that may need to perform modifications to its protective relays or protection philosophies to achieve compliance with the standard and reliable fault protection.

These last two majority comment themes resulted in changes to the standard.

(3) Two comments supported by at least 18 entities were concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

(4) Approximately six comments supported by at least 20 entities revealed a lack of clarity in the basis for the standard. To address this lack of clarity, the drafting team provided detail in the responses below and made minor clarifications in the Guidelines and Technical Basis when the drafting team restructured Table 1 in Attachment 1 based on other comments.

The remaining comment themes were minority issues. The next three resulted in a change to the standard.

(5) Approximately two comments from at least two separate entities raised concerns about what load-responsive protective relays were applicable based on connection or configuration. The drafting team resolved this minority issue by clarifying the Applicability section of standard and adding clarifying text and examples to the Guidelines and Technical Basis.

(6) Approximately two comments from at least two separate entities were concerned that the standard may also apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(7) One comment supported by at least four entities expressed to the drafting team there is a lack of clarity in the application of Attachment 1, Table 1. The drafting team addressed this issue by restructuring Table 1 by Application and Relay Type as well as adding table formatting to draw attention to the various groups of applications and relay types.

The remaining three minority comment themes did not result in a change to the standard.

(8) There was one comment also supported by at least four entities that raised concern that the standard encourages Generator Owners to exceed the manufacturer’s rating of equipment. The drafting team responded to this by explaining that the performance specified

within the standard's criteria does not represent an intentional operating point, but instead represents a natural behavior of generator excitation systems to abnormal system conditions. The Mvar capability is a function of the field-forcing capability of the exciter/field during a system disturbance.

(9) There was one comment supported by at least two entities that raised concern that the standard did not include provisions for a light load condition (i.e., 40%). This condition was originally considered by the drafting team; however, through analysis it was discovered that the second or lighter operating load point offered no additional reliability benefit, only confusion.

(10) One comment by an entity was concerned about the potential overlap between the PRC-024-1 currently under development and the draft PRC-025-1 standard. The drafting team previously identified this issue and coordinated with the PRC-024-1 drafting team to have the load-responsive protective relay references removed from the PRC-024-1 footnote to provide greater distinction between the standards. Also, this entity raised a concern that PRC-025-1 maybe in conflict with standards PRC-019-1. The drafting team reviewed this standard and determined that PRC-019-1 pertains to coordination of applicable protective functions with automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict.

Organization	Yes or No	Question 2 Comment
Ameren	No	(1) We have reviewed in detail our own and SERC-wide performance for the last 6 years, and have not had a single generator protection Misoperation because of relay loadability (for Ameren we cannot recall such an operation in the last 30 years.) It appears that the SDT relies too much on the 2003 blackout single event and empirical data for its justification. While we agree it is desirable to protect the generator and meet the loadability objective, protection equipment changes and/or additions are not justified. **Response:** The drafting team has developed the standard in accordance with the regulatory directives concerning generator relay loadability. The directives are an outcome of the 2003 blackout report and revealed the need to improve generator relay loadability. The goal of the standard is to provide a conservative margin based on generation unit output for which each Generator Owner shall set its load-responsive protective relays. No change made. (2) Please state the total number of generators that tripped in the 2003 blackout to provide proper context. Also, did 2003 blackout post mortem simulations show that had these 28 generators (8 tripped by phase distance and 20 tripped by overcurrent) ridden through the

Organization	Yes or No	Question 2 Comment
		event, the blackout would have been avoided or significantly smaller? **Response:** The drafting team notes that per the 'Power Plant and Transmission System Coordination' – July 2010 – The total number of generators that tripped in the 2003 blackout is 290; eight of those by phase distance and 20 more by 51V protection. Additionally, the cause of tripping for 96 generators is unknown, either because the generator failed to respond to data requests or because the Generator Owner was not able to determine the cause. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) Paragraph 102 of FERC Order 733 does not provide adequate rationale for attachment 1. Paragraph 102 in the Order is discussing Entergy's treatment of GSU and auxiliary transformers. This question is inaccurate and needs to be clarified in order to provide an appropriate answer. **Response:** The drafting team apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made. (2) If the drafting team is referring to paragraph 104, by addressing GSU and auxiliary transformer loadability is addressed in a timely manner and in a way that is coordinated with the outcomes of PRC-023-1, we feel there is more coordination that must be done. Currently, PRC-023-2 is now in effect and potentially has applicability requirements for GSUs and auxiliary transformers. For example, applicability section 4.2.1.6 and Attachment A 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." The drafting team must separate the standards to avoid overlap. While we understand that the Commission did not require a separate standard, now that NERC that decided to approach this issue by developing PRC-025-1, it needs to revise PRC-023-2 as well.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. (3) The technical document that is referenced, "NERC Technical Reference on Power Plant and Transmission System Protection Coordination" explicitly states that "there is limited information available that directly addresses which protection functions are appropriate for BES conditions and which were undesired operations." This document is prefaced with the fact that the authors are unsure of what are appropriate settings for protective relays; rather it addresses the coordination of each of the generator protection functions with the transmission system protection. This is not adequate rationale. **Response:** The drafting team notes that since the referenced document was published, additional study has been undertaken, involving 67 simulations of performance of actual generators for the abnormal conditions anticipated by this standard and for the actual conditions observed on August 14, 2003. These simulations have clearly revealed that generators can approach or achieve the level performance specified in the standard and thus not cause a disturbance to deepen. No change made.
Response: Thank you for your comments, please see the responses provided above.		
American Electric Power	No	AEP has the following concerns regarding the settings options. The 0.85 per unit transmission bus voltage will never be seen by Generators with a delta connection to the Generator Step Up transformer. In order to drop the generator bus voltage to support the 0.85 transmission bus voltage, the unit would need to reduce the Real Power output. Even with reducing the Real Power output and increasing the Reactive Power output, the unit may not be able to withstand the lower voltage. Motors may trip out when connected to a lower generator bus voltage, which could cause additional operating issues and potentially leading to a trip of the unit itself.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comment and notes that a system voltage level of 0.85 per unit represents what may be a recoverable system disturbance. The drafting team agrees that generators are unlikely to see 0.85 per unit voltage at the generator terminal. The standard is addressing the natural short-term response of the generator excitation system to such undervoltage conditions. It is entirely likely that the generator will not be able to support this voltage continuously but it will do as much as possible in the period of system recovery. The criteria related to unit auxiliary transformers attempts to address the concern relative to auxiliary bus loads. The concerns raised relative to motors and auxiliary equipment are not within the scope of the project. Only the generator unit, generator step-up transformer and unit auxiliary transformers are within the scope of the standard. No change made.		
South Carolina Electric and Gas	No	Considering Figures 1 & 2, it is unclear whether the intent is to include station auxiliary transformers that feed plant loads when the unit is offline or in the process of startup. **Response:** The drafting team believes the standard provides sufficient clarity to which unit auxiliary transformers (i.e., UAT) load-responsive protective relays are applicable and that an exception is not necessary. Only the unit auxiliary transformers (i.e., UAT) load-responsive protective relays which are used to provide overall auxiliary power to the generator station when the generator is running (i.e., on-line) are applicable to the standard. Refer to the Applicability section (3.2.3), the accompanying footnote #1 and the unit auxiliary transformers section of the Guidelines and Technical Basis for additional information. No change made. An exception should be made for transformers that do not feed plant loads during normal unit online operation. **Response:** The drafting team notes that in Section 3.2.3 of the Applicability section and the related footnote 1 "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." addresses this issue. No change made.
Response: Thank you for your comments, please see the responses provided above.		
New York Power Authority	No	For the Unit Auxiliary Transformer, the Technical Basis and Guidelines does not take into account the 51 element being set below 150% of rated but with a significant time delay

Organization	Yes or No	Question 2 Comment
		setting to provide backup protection for the feeder protection.

Response: The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made.

The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change **made.**

The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards.

Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made.

The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made.

Organization	Yes or No	Question 2 Comment
ATCO Power	No	I think you are trying to handle the case where the transmission system voltage becomes depressed to 0.85 pu. This does not cause the voltage at the armature terminals of the generator to change, except in a transient time frame (or if the AVR is in manual or drooped). During the transient time frame, the armature terminal voltage would be depressed to 1-(0.15 * (Xd'/(Xd'+Xt)) pu volts (Xt=transformer reactance (pu), Xd'=transient machine reactance, pu), but this will reduce, not increase, the reactive power output, so the worst case for voltage support is in the steady-state time frame after the AVR corrects the

Organization	Yes or No	Question 2 Comment
		voltage. After the AVR corrects the voltage, the armature terminals will return to approximately 1 pu voltage (or whatever it was set at before the disturbance) and the VAR outflow will be the transformer MVA times 0.15/%IZ (0.15 = 1-0.85 = amount voltage is depressed, %IZ transformer rated impedance). (This is just Ohm's law applied to the voltage difference across the output transformer between 1 pu armature voltage and 0.85 pu system voltage.) There is no reason to require simulations to find this value; it can be easily calculated. (The 150% assumption is another way of saying, "assume the output transformer impedance is 10% on a base of the generator maximum real power" -- and it often isn't.) If you want to be sure to cover all possible real power loadings, draw a horizontal line across the PQ plane parallel to the P axis at this value. (This is true unless we assume a voltage depression will only happen at certain loadings -- why? which ones?) This horizontal line corresponds to a mho circle with a diameter equal to Xt/0.15, 90 degrees MTA, and zero offset. So if the goal is, "permit generators to ride through 0.85 pu transmission voltage depressions without tripping on 21 relays", then require that 21 settings lie inside a mho circle with a diameter/reach of Xt/(0.15 * 1.15), 90 degrees MTA, and zero offset. (The 1.15 is the 115% calibration fudge factor.) The technical basis does not support asking for more than this, and asking for less will not accomplish the apparent objective unless we can somehow guarantee that we don't care about spurious trips at certain loadings (which may be due to power swings.) In my opinion, analysis should precede simulation.
Response: The drafting team thanks you for your comment and notes that a system voltage level of 0.85 per unit represents what may be a recoverable system disturbance. The Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing shall not be inhibited from operations during the event. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. No change made.		
Duke Energy	No	It is difficult to comment on the criteria, as we are not familiar with the train of thought used to derive them. Not all of the criteria are described in the Technical Basis section.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the		

Organization	Yes or No	Question 2 Comment
available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
Luminant	No	Luminant agrees that a reasonable approach was used to define limits based on unit MVA ratings for relays susceptible to load. However, the drafting team does not address the coordination of the relay with transmission relaying as described in FERC Order 733, paragraph 107. The Commission directed the ERO to address relay loadability that facilitates the reliability goal of ensuring coordination between transmission and generator protection systems, as required by PRC-001 (draft standard PRC-027). Luminant recommends adding Transmission Owners to the Applicability Section and include relay coordination with the Transmission Owner for each applicable load responsive relay as a separate requirement and measure.
Response: The drafting team thanks you for your comment and notes that relay coordination is not applicable because the standard does not involve timing elements which would require coordination with other reliability functions. No change made.		
Los Angeles Department of Water and Power	No	Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). **Response:** The drafting team notes that that referring to the posted standard that Options 1-4 (now Options 1a, 1b, 1c, and 4) apply to each generator unit and Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). Each option in Table 1 provide the specific Pickup Setting Criteria (i.e., margins) for the load-responsive protective relay types (i.e., time overcurrent, distance, etc.) in the Relay Type column; for generators (i.e., synchronous or asynchronous) specified in the Application column at a voltage corresponding to the criteria used in the Bus Voltage column. No change made. For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes that Figures 1 and 2 are examples of unit auxiliary transformer (UAT) connection configurations. No change made.
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	Recommend the phrase “while maintaining reliable protection” be removed as it introduces ambiguity into R1. Although the SDT attempts to clarify the phrase within the “Guidelines and Technical Basis”, the NSRF is concerned that the phrase’s inclusion will only result in future requests for Interpretation as entities are forced to explain and defend their desired protection goals. Rather than rely on the “Guidelines and Technical Basis”, we recommend the following changes to R1 be made: R1. Each Generator Owner shall install settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection.
Response: The drafting team thanks you for your comment and has added the word “fault” in the phrase “while maintaining reliable [fault] protection” in Requirement R1. Change made. The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made.		
Pepco Holdings Inc. & Affiliates	No	Section 3.1 and Appendix E of the NERC SPSC Technical Reference Document “Power Plant and Transmission System Protection Coordination” describes two separate loading points that should be examined to ensure adequate generator relay loadability during extreme system conditions. One is the loading condition chosen in PRC-025-1 (MW = rated MW ; MVAR = 1.5 x rated MW). The other loading condition is with a lower power output, but with a higher var output (MW= 0.4 x rated MW ; MVAR = 1.75 x rated MW). The SPCS document illustrates that depending on the maximum torque angle setting of the distance element that this second loading condition may become the limiting criteria. The Technical Basis and Guidelines in PRC-025-1 refers to this SPCS document several times, but it does

Organization	Yes or No	Question 2 Comment
		not mention this second loading condition, or the rationale for ignoring it when developing the chosen setting criteria.
Response: The drafting team removed the 40% (i.e., light loading) point from the standard following further simulation. Analysis determined the 40% load point did not change the outcome of the standard being based on the 100% (i.e., full load) load point of generation unit's nameplate rating. The 100% load point achieves an overall conservative margin for setting load-responsive protective relays on generators. This determination is reflected in the team's August 30, 2012 Meeting Notes posted on the NERC website project page. No change made.		
ReliabiltiyFirst	No	The criteria are much more restrictive than that of the IEEE C37.102 recommendations. As the guide states in regards to a general distance setting of 150 to 200% of the generator MVA rating, "However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." Some of the options for phase distance protection may severely restrict the remote backup protection from the generator. The criteria may prevent the generator backup protection from seeing uncleared faults on the remote ends of lines connected to the plant. It is also not clear whether load encroachment methods would work as referenced in the guidelines since the angle of power flow may be near 60 degrees. Load encroachment at these high angles would cut out most of the reach characteristic and allow little margin for detecting arcing. **Response:** The drafting team notes that whether or not load encroachment or blinders are effective requires a case by case analysis. If this approach is used, the entity must determine the generator unit's ability to operate at all load levels. No change made. The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during

Organization	Yes or No	Question 2 Comment
		stressed conditions to the extent possible. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Southern Company	No	The rationale seems to ignore the fact that most generators do not operate any of their equipment beyond the manufacturer's ratings in overloaded conditions. The practices suggested by Table 1 seem to be patterned on transmission line loading practices, which are different than the practices used by generators. **Response:** The drafting team notes that the Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing that will occur during abnormal system conditions is not affected by compromised equipment. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. The drafting team does not believe that entities will change settings when the unit is de-rated. No change made. Generator step up transformers and station auxiliary transformers are generally not allowed to be subjected to short term overload conditions. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. We disagree with the suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18. Suggesting that an entity’s existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing philosoply of protection used by many companies has proven (over multiple decades) to be adequate for protecting

Organization	Yes or No	Question 2 Comment
		our equipment and providing reliable power supply to customers. **Response:** The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. The NERC Glossary states the following definition for Equipment Rating: "The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner." The acceptable amount of risk to power equipment evident through margin in the protection settings rests with the equipment owner. We are concerned that the NERC standards will take this away from the equipment owner. This is especially concerning where automatic protection is required and must operate quickly to prevent significant major equipment damage. Reliance on operator intervention to protect the equipment, in this case, is not practical. Adequate margins of protection must be allowed to be maintained in the automatic trip settings. We believe adequate protection is a fundamental tenet for BES reliability to ensure the equipment can be restored to service quickly. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform

Organization	Yes or No	Question 2 Comment
		modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	The Standard Drafting Team needs to revisit this question. Reviewing the PRC-025-1 SAR, Attachment 1, Order No 733 - Action Plan and Timetable, paragraph 102 is not listed as a significant paragraph of Order 733, or for this standard. FERC Order 733, p102, is a comment from Entergy. Reviewing supporting PRC-025-01 background information on the NERC website, there is no reference to FERC Order 733, p102. This question needs to be re-asked with correct FERC Order references.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comments and apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made.		
Detroit Edison	No	With the exception of Auxiliary Transformers, this standard appears to be concerned with relay elements that operate for power flow toward the transmission system. Distance elements and directional overcurrent relays not "looking" toward the transmission system should not be in scope. Perhaps a statement to this effect in the Technical Basis would be beneficial.
Response: The drafting team thanks you for your comments. The 21 (and 67 – added in draft 2) relay function is directional toward the transmission system in the standard. No change made.		
PPL and Affiliates	No	1. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. ***Drafting team observation:*** *PPL changed the phrase NAGF's comment #6 found in Question #5, "whether or not our calculations," to "whether our calculations." Please see response below.* 2. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new

Organization	Yes or No	Question 2 Comment
		requirements. ***Drafting team observation:*** *PPL #2 is consistent with NAGF's comment #6 found in Question #5. Please see response below.* 3. This is not a minor concern. In addition to the thermal damage posed in some cases by the proposed PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. ***Drafting team observation:*** *PPL #3 changed the phrase in NAGF's comment #6 found in Question #5, by adding "the proposed" making "cases by [the proposed] PRC-025-1." Please see response below.* 4. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. ***Drafting team observation:*** *PPL #4 is consistent with NAGF's comment #6 found in Question #5. Please see response below.* 5. Consistent with FERC's March 15, 2012 FFT Order, standards or requirements should not be adopted that have little or no effect on reliability or because of costs that are not justified by the reliability benefits. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an requirement is applicable, imposing burdens with little or no identifiable benefit for perhaps 80% of all NERC-registered units. ***Drafting team observation:*** *PPL #5 has made non-substantive changes to phrases used in NAGF's comment #6 found in Question #5, and has not changed the nature of comment."*

Organization	Yes or No	Question 2 Comment
		Please see response below. 6. An exception should be made similar to the one proposed in PRC-024 R3 of the generator verification standards and should state, “Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer’s advisory.” ***Drafting team observation:*** *PPL #5 has made non-substantive changes to phrases used in NAGF’s comment #6 found in Question #5, and has not changed the nature of comment.” Please see response below.*
Response: The drafting team thanks you for your comments. PPL and Affiliates has submitted, except as noted by the drafting team the same comments #1 through #6 above, as those prepared by the North American Generator Forum (NAGF) comment #6 found in Question #5 below. Please refer to drafting team’s response to NAGF’s comment #6 below in Question #5.		
Ingleside Cogeneration LP	Yes	From a technical perspective, Ingleside Cogeneration found this section was soundly grounded. However, we believe that there is no rational basis that the standard apply to generators which have minimal impact on BES reliability - analogous to the 200 kV voltage threshold for transmission lines in PRC-023-2. The justification needs to be captured in the Technical Basis and Guidelines section, although the criteria itself would appear in the Applicability section. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. The drafting team considered approaches to limiting the applicability but determined that “minimal impact” is a superfluous term that the standard should be applicability to all BES generators. No change made.

Organization	Yes or No	Question 2 Comment
		Secondly, there needs to be further discussion concerning the interaction of the relay loadability thresholds with those required under Project 2007-09 Generation Verification - particularly PRC-024-1 and PRC-019-1. At present, every one of these standards are written in a manner that calls for the Generator Owner to comply with their requirements, and to figure out how to make them all work together. Even though we agree that the ultimate goal to improve generator availability will greatly serve BES reliability, ICLP does not believe this kind of approach is reasonable - and may lead to violations even when the GO is heavily committed to the task. **Response:** The drafting team notes that PRC-019 is focused on coordination between AVR control and its protection setting. The objective in PRC-025-1 is to ensure the field forcing capability of the machine is used to allow the machine to stay on-line for a recoverable system disturbance. The drafting team recognized the duplication and coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that the load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made.
Response: Thank you for your support and comments, please see the responses provided above.		
Wisconsin Electric Power Company	Yes	
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards	Yes	

Organization	Yes or No	Question 2 Comment
Development Team		
Dominion	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
Tacoma Power	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	

3. **Does PRC-025-1, Attachment 1: Relay Settings, Table 1 clearly identify the criteria for setting load-responsive protective relay types for each Option 1 through 17? If not, provide specific detail that would improve the clarity of Table 1.**

Summary Consideration:

Approximately 22 commenters support by at least 63 entities provided comment for question #3. There were at least 14 common themes presented by commenters, of those, about three comments represented the majority opinions by comment count and entities represented.

The first three majority comment themes resulted in changes to the standard.

(1) More than 30 comments supported by at least 40 entities were concerned about how to perform calculations, a lack of clarity in the Attachment 1, how to address different conditions such as varying generator output, and the need for figures and examples. The drafting team addressed these concerns by clarifying Attachment 1, rewriting the Guidelines and Technical Basis to coincide with the various options available to entities, and providing a series of calculations for the options.

(2) Approximately nine comments supported by at least 37 entities expressed to the drafting team there is a lack of clarity in the application of Attachment 1, Table 1. The drafting team addressed this issue by restructuring Table 1 by Application and Relay Type, as well as adding table formatting to draw attention to the various groups of applications and relay types.

(3) Approximately seven comments supported by at least 13 entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as “field-forcing,” and is a relay loadability issue, not an overload condition. This duration is within the generator field thermal overload limits raised by these comments. Additionally, there were concerns about why IEEE C37.102 is not adequate and the necessity of the standard. The drafting team contends that IEEE C37.102 represents general protection and that the standard is addressing protection criteria in greater specificity, as well as a regulatory directive related to concerns identified following the August 14, 2003 Northeast blackout.

The remaining 11 comment themes were minority issues and the next six discussed here did not result in changes to the standard.

(4) About three comments supported by at least eight entities were received questioning the basis for including equipment like the unit auxiliary transformers (UAT) and questioning why out-of-step protective relays were not included in the standard. The drafting team responded that UAT facilities are included to address a regulatory directive and out-of-step relays are subject to the next phase of this project which will be Project 2010-13.3 – Stable Power Swings (Phase III).

(5) Two comments supported by at least 10 entities suggested greater flexibility in setting their load-responsive protective relays. The drafting team responded that the standard by the use of options has provided this flexibility. To determine settings, an entity may select a simple calculation, a more complex and precise calculation, or the most precise method using simulation. Additionally, the standard provides each entity the ability to set its load-responsive protective relays to exceed the values required by the Table 1 in Attachment 1.

(6) Two comments supported by three entities questioned why the standard did not follow the format of standard, PRC-023-2 – Transmission Relay Loadability. The drafting responded that for transmission loadability a wide variety of topologies affect the loadability resulting in many different criteria. Generating plant relay loadability is instead affected by the innate capability of the generator resulting in a smaller set of available criteria. Also, that the criteria specified in PRC-023-2 – Transmission Relay Loadability would not support the short-term performance that will be observed by generation plants for system disturbances and would therefore result in undesired trips of the generating plant.

(7) There were two comments supported by at least three entities that raised concern that the standard did not include provisions for a light load condition (i.e., 40%). This condition was originally considered by the drafting team; however, through analysis it was discovered that the second or lighter operating load point offered no additional reliability benefit, only confusion.

(8) Two comments supported by at least three entities raised concern that PRC-025-1 maybe in conflict with standard PRC-019. The drafting team reviewed this standard and determined that PRC-019 pertains to coordination of applicable protective functions with automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict.

(9) Two comments supported by at least eight entities were concerned that entities may need to perform modifications to their protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the standard provides suitable options to address the issue and the drafting team has developed the implementation plan to accommodate that an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard.

The remaining five minority comment themes were issues that resulted in changes to the standard.

(10) Three comments supported by at least six separate entities raised concerns about how to determine if load-responsive protective relays were applicable based on connection or configuration. The drafting team resolved this minority issue by clarifying the Applicability section of standard, modifying Table 1, and adding examples to the Guidelines and Technical Basis.

(11) Approximately four comments supported by individual entities raised concerns about the calculation of the settings based on seasonal output capability. The drafting team addressed this through a clarification in Attachment 1, Table 1. The calculation for Real Power output is the MW capability reported to the Planning Authority or Transmission Planner and the Reactive Power output, in Mvar, is based on the MW value derived from the generator unit's nameplate MVA at rated power factor times 150%.

(12) Two comments supported by at least six entities suggested changing the IEEE function numbers for voltage-restrained (e.g., 51V) and voltage-controlled (e.g., 51VC) protective relays to the nomenclature V-R and V-C for greater clarity and consistency. The drafting team agreed and made the change throughout the standard.

(13) Two comments supported by at least five entities were concerned that the standard may apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team revised the standard and provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(14) Approximately three comments supported by individual entities raised concerns about a lack of clarity in dealing with generator step-up (GSU) transformer winding taps, on-load tap changers (OLTC), and no-load tap changers (NLTC). The drafting team addressed these comments by providing example calculations and additional text in the Guidelines and Technical Basis.

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	No	(1) For all 21 - Phase Distance Relays (Option 1 - 4 and Option 13 - 16): The setting criteria did not mention the maximum reach angle of the impedance element setting. Should this be considered and clarified? **Response:** The drafting team notes that the maximum reach angle is based on the characteristics of the protected equipment and is left to the user to determine. No change made. (2) For 51V - Phase Time Overcurrent Relays, voltage-restrained, (Option 5 & 6): Following this setting criteria could make detecting faults on the high side of the step-up transformer very difficult especially considering that transient or synchronous machine impedance (X'd or Xd instead of X"d) is used for fault calculation. **Response:** The drafting team notes that, if the entity discovers that the relay cannot be used to provide protection and to meet the standard, alternate protection strategies should be pursued. No change made. (3) For the 51 relays on the step-up transformers (Option 10): Following this setting criteria could mean that the pickup setting could be 175% of nameplate rating of the transformers. Should there be any concern with the transformer overload and mechanical damage as a

Organization	Yes or No	Question 3 Comment
		result? Also, the 175% setting is not consistent with the 150% number in the Transmission Relay Loadability standard. **Response:** The drafting team removed the 40% (i.e., light loading) point from the standard following further simulation. Analysis determined the 40% load point did not change the outcome of the standard being based on the 100% (i.e., full load) load point of generation unit's nameplate rating. The 100% load point achieves an overall conservative margin for setting load-responsive protective relays on generators. This determination is reflected in the team's August 30, 2012 Meeting Notes posted on the NERC website project page. No change made. (4) The "Bus Voltage" criteria are not clearly defined and should be clarified. For example, in Option 1, the generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage would vary depending on the current going through the transformer. Also, option 2 in the table makes reference to "on the high side" and option 1 in the table makes reference to "of the high side". Should these all read 'of'? **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.

Organization	Yes or No	Question 3 Comment
		(5) Given 'gross MW' and 'terminal voltage', how would we calculate current in order to calculate the generator bus voltage? **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (6) What is meant by "maximum seasonal gross MW"? Is this the nameplate MW? Is this the MW calculated for MOD-024? If so, a reference should be made to this standard. **Response:** The drafting team notes that Attachment 1 has been revised to add "capability" reported to the Planning Coordinator or Transmission Planner. If the gross MW capability reported to the Planning Coordinator or Transmission Planner varies seasonally, the drafting team intends that the highest of the various seasonal capabilities be used by the Generator Owner. If from year to year the capability for any specific season varies the entity may need to reevaluate their protection if the newest maximum gross MW capability has increased from that previously used. The drafting team does not anticipate that entities will unnecessarily change settings if the maximum gross MW capability decreases. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Ameren	No	(1) The first sentence implies that only "one" of the 17 Options needs to be met. Actually Option 17 almost always must be met as well as one of the first 16 Options. In cases using different relay types for the generator two of the first 16 Options need to be met. **Response:** The drafting team notes the first sentences states that the Generator Owner shall use "one of the following Options 1-17 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay according to its application." Only one option may be used per load-response protective relay according to its application. The drafting team has re-arranged the table and the option numbers have changed. (2) Our reading is that the 115% is applied to the loading criteria prior to calculating the impedance or current Pickup Setting Criteria. An example for Options 2 and 5 would

Organization	Yes or No	Question 3 Comment
		provide clarity and help reach your loadability objectives without trapping the GO into unintended non-compliance. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (3) Our reading is that Bus Voltage instructions for Option 1 ignore the IZ voltage rise through the GSU but include it for Option 2. Is that the SDT's intention? **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (4) The last part of p 7 paragraph 2 states the Reactive Power capability is calculated at rated power factor (typically 0.8 to 0.9) which conflicts with the Table 1 Pickup Setting Criteria which uses Reactive Power equal to 150% of rated MW. We suggest to correct this discrepancy.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes that the second paragraph in Attachment 1 has been corrected. Change made. (5) PRC-023 provides a wider range of criteria for meeting transmission loadability. **Response:** The drafting team notes that for transmission loadability a wide variety of topologies affect the loadability resulting in many different criteria. Generating plant relay loadability is instead affected by the innate capability of the generator resulting in a smaller set of available criteria. No change made. (6) An entity may be forced to reduce the Real Power capability it reports to the Planning Coordinator in order to meet the standard as proposed. This would have an adverse impact on BES reliability. **Response:** The drafting team does not believe that an entity would find it attractive to reduce generator capability but instead would perform protective system modifications as necessary to achieve the requirements of the standard. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) We find the criteria confusing and needing further clarification. First, we suggest dividing the table into multiple tables based on the relay type and application. This will make it clear that GO does not have 17 options but rather has only three options for Phase Distance Relays (21) protecting synchronous generators. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. Second, we are confused about the difference in the bus voltage column for options 1 and 2. Both options apply to the generator bus and voltage is calculated from the high side of the generator step up (GSU) voltage. Option 1 allows the voltage to be set at 0.95 pu and

Organization	Yes or No	Question 3 Comment
		option 2 allows the voltage to be set at 0.85. Option 2 mentions using the GSU impedance in addition to the turns ratio to calculate the generator bus voltage from the high side whereas option 1 only mentions the turns ratio. If the intention is to include the GSU impedance in one calculation and not the other, does it make sense to have a voltage difference of 10%? To drop voltage 10% across a GSU would require a very high impedance transformer. Please provide further clarification. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. As currently defined, we believe that option 1 will always be selected because it is simply less restrictive. We note that similar issues exist between Options 5 and 6 and Options 13 and 14. We assume the voltage identified in the bus voltage column of options 10-12 applies to the generator bus. It is not clear if the impedance of the GSU is to be considered for these options. We assume it would be but there is so much less information provided than in the other options so it is not clear and is not explained in the technical guidelines. **Response:** The drafting team believes that Option 2 (now 1b) while more complex may provide a less restrictive setting, not Option 1 (now 1a). No change made.
Response: Thank you for your comments, please see the responses provided above.		

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Affiliates	No	1) Options 1, 5 and 13 should be eliminated, or a qualification should be added that these options may only be used if the generator step-up transformer reactance is greater than some specified threshold amount. It is true that due to the voltage drop across the transformer, the generator voltage will be higher than the system voltage. This can be seen from the following equation: Vgen = Vsys + Igen x (j Xt). Assume the generator is operating at a loading condition of S = 1.532@56.31 pu MVA, which is the maximum anticipated loading condition identified both in this standard, as well as in the SPCS document (ref. Appendix E). Assume the generator voltage Vgen is 0.95@0 pu, as allowed in Options 1, 5, and 13. Since S = VI*, Igen can be found as 1.613@-56.31 pu. By then solving for Vsys, one can see that Vsys will be greater than 0.85 pu, whenever Xt is smaller than 0.076pu (Xt < 7.6%). While most GSU transformers have a reactance equal to, or greater, than this value, some may not. Since all loadability criteria must be based on a system voltage of 0.85 pu, the choice of Vgen = 0.95 pu is appropriate only if the application is restricted to GSU's with sufficient reactance to ensure the application results in a corresponding system voltage of 0.85 pu, or lower. Options 2, 3, 6, 7, 14, and 15 are not an issue, because they assume a system voltage of 0.85 pu and then require a calculation, or simulation, to obtain the corresponding generator voltage to be used in the evaluation. Finally, if the SDT decides to retain Options 1, 5, and 13 then the Guidelines and Technical Basis section should be revised to address the technical justification for the choice of a 0.95 pu generator voltage. **Response:** The drafting team believes the settings calculated in options 1, 5 and 13 are reasonable proxies for options 2, 6 and 14 (now 1b, 2b, and 7b), respectively and for those entities who wish to use options 1, 5 and 13 (now 1a, 2a, and 7a)will represent a considerable simpler calculation. No change made. 2) The ANSI number 51V-R should be used instead of 51V to represent voltage restrained overcurrent relays, and 51V-C should be used instead of 51C to represent voltage controlled overcurrent relays. Using 51V-R and 51V-C avoids confusion, since 51V is often used to represent both types of relays. Also the 51V-R and 51V-C terminology is consistent with

Organization	Yes or No	Question 3 Comment
		that used in the SPCS Technical Reference Document. **Response:** The drafting team agrees that using V-R for voltage restrained and V-C for voltage-controlled relays as used in the NERC Power Plant and Transmission System Protection Coordination document adds clarity; therefore, has modified the standard as suggested. Change made. 3) In the Guidelines and Technical Basis portion of the standard it states "If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics." However, the standard does not provide any specific criteria, or methodology, on how to evaluate relay loadability if these techniques are employed. Table 1 simply states that the 21 element (assumed to be a non-offset mho element) should be set with a maximum reach less than the apparent impedance described, apparently regardless of the setting of the maximum torque angle of the relay. If blinders, or load encroachment techniques were used to accommodate the one specific loadability point described in the standard, aren't there other loadability constraints that also need to be addressed? **Response:** The drafting team notes that the standard defines the loadability constraints that must be addressed to meet the objective of the standard. No change made. The Technical Basis portion of the standard points out the concern that altering the shape to achieve a longer reach may restrict the capability of the unit when operating at a real power output other than 100%. Therefore, to cover all applications, the PRC-025-1 standard should describe loadability criteria irrespective of the type, or shape, of the impedance characteristic used. To accomplish this, perhaps a better set of setting criteria would be as follows: "The phase distance protective characteristic should be set, assuming a generator voltage as specified in the column labeled bus voltage, so as to not operate under any of the following three

Organization	Yes or No	Question 3 Comment
		loading conditions: a) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (100% of Maximum MW; Reactive Power equal to 150% of rated MW). b) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (40% of Maximum MW; Reactive Power equal to 175% of rated MW). c) Generator supplying power (as measured at the generator terminals) within its published capability curve." **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made. Plotting these three constraints on the R-X impedance plane would allow one to choose a phase distance characteristic (with, or without, load encroachment, or blinders) that would be immune from operating under these specific loading conditions. The third condition would effectively limit the reach of the element so as to not restrict the reactive capability of the unit. This last issue is very important, since in the latest draft of PRC-019 the coordination of the phase distance element with the generator reactive capability curve was specifically removed, implying that it would be addressed in the PRC-025 loadability standard. **Response:** The drafting team notes the PRC-025-1 is not for the fault or steady state condition, but for the field-forcing condition (short-term). Coordination with AVR response is anticipated to be covered by PRC-019 currently in development and coordination with the transmission system is covered by the existing PRC-001-1 and PRC-027-1 which is under development. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Nebraska Public Power District	No	1) Table 1, Option 1. "Generator bus voltage corresponding to .95 pu of the high side nominal voltage times the turns ratio of the generator step-up transformer". For example,

Organization	Yes or No	Question 3 Comment
		one of our plants GSU has a high side of 345kv nominal and has a generator nominal voltage of 23kv. Do we assume 345kv/23kv = 15 ratio or do they use the actual ratio which has a tap of 345 and tap of 23.4 = 14.74 ratio. One Generator voltage could be 0.95 x 345 / 15 = 21.85 kv or the Generator voltage could be 0.95 x 345 / 14.74 = 22.24kv. Do we use the Generator bus voltage of 21.85kv, 22.24kv, or is the calculation wrong. If this can be clarified or an example provided this would be helpful. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 2) Table 1, Option 1. "The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output - 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output - a value that equates to 150% of rated MW. Can you give an example calculation. Our unit is a 757MVA unit. Lets assume our maximum Seasonal gross MW is 650MW. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. i. Real Power is 650MW ii. Reactive Power is 975MVAR iii. MVA = 1.15 x SQRT (650 x 650 + 975 x 975) = 1348 MVA at 56 degrees. Do we find the impedance of this MVA value at 56 degrees and the 0.95 bus voltage? If this can be clarified or an example provided this would be helpful. The KD 21 relay is a 75 degree relay so how do we account for the power factor of the relay, power factor of load, and power factor from the MVA with your table. Can you give an example calculation? **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 3) Table 1, Option 10. Can you give an example calculation for option 10. How is an

Organization	Yes or No	Question 3 Comment
		overcurrent affected by voltage? For a 757MVA, 23KV the FLA is 19,002 amps. Can you give an example for setting the 51 relay. Do we calculate the MVA as shown in step 2.iii above then use the 0.85 x (345 / 15) or 0.85 x (345 / 14.74) to obtain the generator voltage so we can calculate the current once the MVA is known. Why are we not selecting 1.5 x FLA. The FLA does not change based on per unit voltage. If this can be clarified or an example provided this would be helpful. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: The drafting team provides the following additional information. 1. The key here is "0.95 per unit of the high side nominal voltage times the generator step-up transformer turns ratio". In this example, 22.24 kV would be used. 2. One would find the magnitude of the complex impedance at 1348 MVA, and adjust the power factor angle (PFA) to the relay maximum torque angle (MTA) by dividing the resulting impedance (either primary or secondary) by the term, "cosine(MTA-PFA)." This will produce a mho relay reach (circular characteristic at its MTA) that will go through the complex impedance value at its PFA. 3. The intent here is the Real Power output (in MW) and the specified Reactive Power output (in MVar) would result in a complex power output (in MVA), that would be translated to amperes at the specified voltage (rather than at rated voltage). It has been the intent of the drafting team to further develop the supporting documents as needed by industry.		
Duke Energy	No	1) If such a table is used; RELAY TYPE should simply be the type of element, such as "Phase Distance - 21", and APPLICATION should be the elements use, such as "Applied on synchronous generator, set to trip for faults in the system direction." Further, the SDT should not separate BUS VOLTAGE and what is called PICKUP SETTING CRITERIA - Together these are defining the system conditions for which the relay is not supposed to pickup. **Response:** The drafting team has restructured the table for clarity. The bus voltage column describes the system behavior to which the option applies. Change made. 2) It is not clear what the intent of the 115% factors specified in Table 1 are. If these are for

Organization	Yes or No	Question 3 Comment
		coordinating margin, this should be expressed so coordination margins are not doubled. **Response:** The drafting team notes that the 115% factor is the margin required within the standard. An entity may choose to apply additional margin if they wish. See the Guidelines and Technical Basis section in the standard. No change made. 3) We recommend using the common designations of 51VC for voltage controlled inverse time overcurrent elements and 51VR for voltage restrained inverse time overcurrent elements. **Response:** The drafting team agrees that using V-R for voltage restrained and V-C for voltage-controlled relays as used in the NERC Power Plant and Transmission System Protection Coordination document adds clarity; therefore, has modified the standard as suggested. Change made. 4) SDT should specify criteria in standard engineering terms. The use of language such as "VArs equal to 150% of rated MW" is not clear. It would be better to specify "Rated Watts at .55 pf lagging." **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 5) We do not understand the differences between several of the options, such as between option 1 & 2. Option 1 is not aligned with Appendix E of the technical guide, and no commentary is provided within the standard. SDT is creating criteria that are outside the mainstream - it must provide more technical information on what the intent and rationale is for each criteria. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar.

Organization	Yes or No	Question 3 Comment
		For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). The drafting team used the document to which you refer as a base document, and altered the criteria in two specific areas: the drafting team determined that the low-power operating point did not meaningfully contribute to reliability and chose to not include it, and also provided a third optional criteria (option 1) which results in even more simple calculations if the entity chooses to use it. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. The drafting team notes that the drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 6) The intent of options 13-16 is not clear. Are these for 21 elements on the high voltage of GSU? If so, why are generator terminal voltages mentioned? **Response:** The drafting team notes that that referring to the posted standard that Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). No change made. 7) We question whether all of the options are required. Many of the system conditions are

Organization	Yes or No	Question 3 Comment
		the same from one application to another. Could the worst case system conditions be presented in paragraph form along with descriptive commentary? **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The drafting team further notes that the Generator Owner shall for each load-responsive protective relay that it applies on BES facilities set be set according to the standard. 8) SDT should consider including recommendations for the traditional 50/27 elements used for inadvertent energization protection. Traditionally the 50 elements of this type are set near 1.5pu. The setting of the voltage element needs to be evaluated such that it will ride through disturbances but also sense voltage during a true inadvertent energization under worst case system conditions. Perhaps these elements should be considered as specialized forms of 51VC. These elements will also need to comply with PRC-025 LVRT criteria. **Response:** The drafting team notes that the application of load-responsive protective relays applicable to the standard only apply while the generator is online. Relays that are armed when the generator is disconnected from the system, enabled during start-up, used for inadvertent energization schemes, open breaker flashover schemes, or and phase fault detector relays are not applicable to the standard. Attachment 1: Relay Settings has been revised to clarify when the load-responsive protective relays are applicable to the standard. Change made. 9) In reference to Option 17: 150% of the maximum transformer rating can be 250% of the base rating. Transformers are not rated to carry 250% continuously. **Response:** The drafting team notes that application of fault protective relays for overload

Organization	Yes or No	Question 3 Comment
		protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable fault protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions.
Response: Thank you for your comments, please see the responses provided above.		
Luminant	No	1. Luminant agrees that although Table 1 in Attachment 1 clearly identifies criteria for setting load responsive relays, it is recommended that the drafting team add information in the Attachment that describes the bus voltage conditions as steady state values only and does not consider relay operations for fault conditions. In addition, a statement that the Generation Owner must coordinate relays with applicable AVR response and transmission relaying. **Response:** The drafting team notes the PRC-025-1 is not for the fault or steady state condition, but for the field-forcing condition (short-term). Coordination with AVR response is anticipated to be covered by PRC-019 currently in development and coordination with the transmission system is covered by the existing PRC-001-1 and PRC-027-1 which is also under development. No change made. 2. Luminant recommends the "Pickup Setting Criteria" column for real power output be revised to "100% of maximum seasonal gross or maximum continuous rating of the turbine reported to the Planning Coordinator". **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the

Organization	Yes or No	Question 3 Comment
		maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. 3. In Row 17 (Auxiliary Transformers - Phase Overcurrent Relay), Luminant recommends that the 150% pickup setting criteria be applicable to the relay regardless of its electrical location (high or low side of the UAT). **Response:** The drafting team has revised the unit auxiliary transformer (UAT) Option 17 (now Option 13a and 13b) to reflect that the voltage depends on the winding voltage regardless of location. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Southern Company	No	Fundamentally, requiring entities to relax preferred protection levels on their equipment with no method of (possible) damage cost recuperation due to more liberal protection settings is not fair to the entities that may incur repair/replacement costs. **Response:** The drafting team notes that the entity is expected to provide necessary protection while meeting the requirements of this standard. If legacy approaches do not allow the entity to meet both, other approaches may be necessary. Options have been added to the unit auxiliary transformer (UAT) criteria to allow calculations based on the actual connected auxiliary bus loads and to allow for auxiliary bus performance simulations. For other elements addressed, options have already been provided for the entity to base the protective relay settings on simulated performance. Change made. Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. We believe that Option 17, related to station auxiliary transformers, is unwarranted,

Organization	Yes or No	Question 3 Comment
		excessively liberal in overload allowance, and does not belong in this standard. The station auxiliary power consumption does not directly contribute to the generator overload ability for supporting system disturbance events. Requiring a station auxiliary transformer HSOC (high side overcurrent) relay to be set at the level specified in Option 17 of Table 1 is not justified. We have, for many years, successfully set the station auxiliary transformer HSOC relay pick up value at a much lower value and have experienced very few misoperations. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. The MW value used in the calculation specifics of Table 1 is unclear. We suggest that the MW value used for the calculations be that realized with applying the generator nameplate MVA rating with the rated power factor also found on the generator nameplate. In the draft standard, the MW value to be used is referred to by many different names, including: -Maximum seasonal gross MW reported to the Planning Coordinator -Rated MW -Total nameplate MW -100% of Connected generation reported Establishing the MW value as suggested above removes all confusion to the GO as to which MW value to use, provides a standard method to use, and is close enough to the other values listed to provide the desired generator loading ability. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria.

Organization	Yes or No	Question 3 Comment
		The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. Table 1 is much too complicated. Options 1-4 and Options 13-16 could easily be combined into one set of four options by modifying the Application column. (For example, the combined Options 1 and Option 4 Application column could be labeled "Synchronous Generator or GSU Xfmr - Synchronous Generator".) Further, Options 1-3 and Options 13-15 should be reduced into one row that specifies the Generator Bus Voltage criteria and the Pickup setting criteria. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The additional methods listed (Options 2, 3, 14, 15) simply confuse the issue. (For example, it is not clear which entity is required to perform a simulation in Options 3, 7, and 15. GO's generally do not have the system simulation software or the system data required to perform this simulation.) For the rows of Table which remain after this simplification, one calculation example per row would be valuable to demonstrate the intented calculation method. **Response:** The drafting team notes that the standard offers multiple options and that the Generator Owner may perform simulations to determine the expected generator performance during the stressed conditions anticipated by the standard. No change made. We are concerned that the setting limits specific in Table 1 are too liberal to provide adequate overload protection to our generating plant equipment. The required minimum sensitivities for the relaying shown in Table 1 for all units based on a minority (20%) representation of unit capability to provide Q forcing ability results in forcing owners of generators to relax typical relay settings that result in loss of adequate overload protection.

Organization	Yes or No	Question 3 Comment
		Entities should be allowed to protect their equipment from overload rather than be forced to allow a specific amount of overload. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made.
Response: Thank you for your comments, please see the responses provided above.		
American Electric Power	No	Generation relay settings typically use the generator bus voltage for calculations. Options 2, 3, 6, 7, 10, 11, 12, 14, 15 and 17 are all expressed as .85 per unit of the transmission system, but should instead be referenced in regards to the generator bus voltage (as Options 1, 4, 5, 8, 9, 13, and 16 are). **Response:** The drafting team notes that the standard requirements are based on the transmission system voltage conditions observed on August 14, 2003. The options that reference the high-side voltage directly reflect this condition. The options that reference the generator bus voltage provide a conservative, but simpler method to approximate the same condition. No change made. Phase distance relays (21) listed in Table 1 should be excluded from any requirements in PRC-023-2- Transmission Relay Loadability. The phase distance relays included in Table 1 can only have settings that will be compliant with one set of requirements not both. Inclusion of these relays in PRC-023-2 and PRC-025-1 would pose a conflict in settings. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection

Organization	Yes or No	Question 3 Comment
		facilities. Change made. Also the out of step relays (78) were listed in PRC-023-2. However, AEP believes that these relays should also be included in Table 1 as a requirement in addition to being an exclusion from PRC-023-2." **Response:** The drafting team notes that out of step tripping of generators will be address in phase three of relay loadability under Project 2010-13.3 – Stable Power Swings and are not within the scope of this project (2010-13.2). Only the generator unit, generator step-up transformer and unit auxiliary transformers are within the scope of the standard. No change made. Seasonal gross Real Power capability" needs to be explicitly defined. **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	It is not clear if it is required for 1 type (21, 51V, 51C, or 51) to be set according to Table 1 or each type.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The drafting team further notes that the Generator Owner shall for each load-responsive protective relay that it applies on BES		

Organization	Yes or No	Question 3 Comment
facilities set be set according to the standard.		
Los Angeles Department of Water and Power	No	Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). **Response:** The drafting team notes that that referring to the posted standard that Options 1-4 (now Options 1a, 1b, 1c, and 4) apply to each generator unit and Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). Each option in Table 1 provide the specific Pickup Setting Criteria (i.e., margins) for the load-responsive protective relay types (i.e., time overcurrent, distance, etc.) in the Relay Type column; for generators (i.e., synchronous or asynchronous) specified in the Application column at a voltage corresponding to the criteria used in the Bus Voltage column. No change made. For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity. **Response:** The drafting team has provided example calculations in the Guidelines and Technical Basis to improve the clarity; however, due to the numerous configurations of other options the drafting team has not developed diagrams for the remaining options. Change made.
Response: Thank you for your comments, please see the responses provided above.		
pacificorp	No	PacifiCorp thermal facilities use impedance elements as backup generators, generator bus and GSU protection where the element does not reach through the GSU. This approach results in impedance magnitudes that are significantly lower than those outlined in the Attachment 1 options. It may be beneficial to generator protection engineers if the standard provides registered entities with an option to calculate the impedance reach of the

Organization	Yes or No	Question 3 Comment
		21 element when it is based on the GSU impedance. **Response:** The drafting team notes that while it is unlikely that phase distance settings based solely on the GSU impedance will be a problem for the conditions anticipated by this standard, the GSU impedance is not reflective of these conditions. No change made. Furthermore, while Options 1-4 & 13-16 in Table 1 specify how to determine the generation facility maximum rating and the per-unit bus voltage to perform the impedance reach calculation, these options are missing: (1) the load (or power factor) angles at which the impedance element reach must be evaluated to ensure compliance, and **Response:** The drafting team notes that the power factor angle is determined by the Real and Reactive Power represented in the criteria in Table 1. No change made. (2) recommendations as to how to set load-encroachment element blinders. PacifiCorp recommends that this information be incorporated into the "Guideline and Technical Basis" section of PRC-025-1 to ensure compliance, using Standard PRC-023-2 "Reference Document" as a model. **Response:** The drafting team notes that whether or not load encroachment or blinders are effective requires a case by case analysis. If this approach is used, the entity must determine the generator unit's ability to operate at all load levels. No change made.
Response: Thank you for your comments, please see the above responses.		
South Carolina Electric and Gas	No	Paragraph 2 of Attachment 1 starting with "Synchronous generator output pickup setting criteria values are determined......" seems to contradict Table 1 regarding the calculation of reactive power output. The paragraph implies that reactive power capability is calculated using the rated power factor however Table 1 implies that it is calculated as a function of rated MW output. **Response:** The drafting team notes that the second paragraph does not reference the

Organization	Yes or No	Question 3 Comment
		power factor as noted in the comment; however, the drafting team has provided examples in the Guidelines and Technical Basis under Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c) to improve the clarity. Change made. It would greatly enhance understanding of Table 1 if some examples calculations. This would allow entities to be confident that they were interpreting the wording of the requirements correctly. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: Thank you for your comments, please see the above responses.		
Detroit Edison	No	Please provide setting examples for each type of relay (21, 51V, etc) using both real and reactive power criteria to clarify how Table 1 should be applied. Also, drawings showing location of applicable relays (CT and PT input sources) would be helpful. Reactive power criteria expressed in terms of MW is confusing.
Response: The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.		
Tacoma Power	No	Referring to Attachment 1, Table 1, Options 2, 3, 6, 7, 14 & 15, what current is to be applied through the transformer impedance? **Response:** The drafting team notes the current to be applied through the transformer is the current related to the Real and Reactive Power at the referenced voltage. No change made. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. Referring to Attachment 1, Table 1, Options 10, 11, 13, 14 & 15, should "Real Power output - 100% of connected generation reported" be changed to something like "Real Power output - 100% of maximum seasonal, aggregate gross MW reported to the Planning Coordinator"? **Response:** The drafting team considered basing the loadability on seasonal output reported

Organization	Yes or No	Question 3 Comment
		to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. Referring to Attachment 1, Table 1, Options 10, 11 & 12, could an exception be granted if the 51 elements are directional toward the generation system? **Response:** The drafting team for Options 10, 11, and 12 (now 8a, 8b, 11a, and 11b) have been augmented to include the phase directional overcurrent (67 function) Relay directional toward the transmission system. See the new Options 9a, 9b, 12 for the phase directional overcurrent (67 function) Relay directional toward the transmission system. The overcurrent element commented above that is directional toward the generation system is now excluded. Change made. Referring to Attachment 1, Table 1, Option 17, should "the element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating" be changed to something like "the element shall be set greater than 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating"? **Response:** The drafting team has substantially modified Option 13a and 13b formerly Option 17. Change Made
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	The NSRF agrees with the criteria described in Option 1 through 17 in Table 1, however, we recommend that the Table 1 be broken up into different tables based on the application and relay type. For example, there should be a table for synchronous machines, and one for

Organization	Yes or No	Question 3 Comment
		GSUs, and etc. This would add clarity to Table 1. The addition of the new tables would require that the Application Guidelines section to refer to the new tables be revised.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
ATCO Power	No	There are three issues: (1) on-load tap changers for output transformers are not handled, **Response:** The drafting team notes that on-load tap changers (OLTC) have time delays which prevent them from responding within the timeframe addressed within this standard and, therefore are not included. The drafting team added discussion in the Guidelines and Technical Basis to improve the clarity that the transformer's taps settings, for certain Options, must be considered. Change made. (2) the 150% reactive outflow assumption is not appropriate when using the calculation option as you can calculate the actual VAR outflow for a 0.85 pu voltage depression quite easily from the transformer impedance unless initial conditions with heavy VAR flows are assumed, and **Response: T**he drafting team notes that it has added clarification of the time frame the standard is addressing to the Guidelines and Technical Basis. The timeframe of concern is during field forcing which precludes the calculations described in your above comment. Therefore, it is necessary to use an approximation based on observed data or a simulation as described in the standard. Change made. (3) the initial conditions for the simulation are not specified (full load and unity power factor with all voltages at 1 pu?) and the conditions for simulating the voltage depression are not specified (no swings or close-in faults?) **Response:** The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator

Organization	Yes or No	Question 3 Comment
		Simulation Criteria. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Texas Reliability Entity	No	TRE suggests the following changes for Attachment 1: Relay Settings, Table 1: a) On page 7 under 'PRC-025-1-Attachment 1: Relay Settings' discussion of the synchronous generator reactive capability calculations is confusing. TRE suggests the following language for Paragraph 2: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined based on the unit's nameplate megavoltampere (MVA) and the calculated rated MW at the unit's rated power factor." **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. b) In the Table 1. Relay Loadability Evaluation Criteria; recommend specifying 'Synchronous generator bus terminal' instead of 'Synchronous generators' in the application column for Options 1, 2, 3, 5, 6 & 7. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e.,

Organization	Yes or No	Question 3 Comment
		Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. c) In the Table 1 - Bus Voltage column, clarify that the generator bus voltage calculation needs to include the generator step-up transformer winding tap setting (NLTC or LTC tap settings) in the turns ratio calculation of the generator step-up transformer, when applicable. Suggested language, "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer. The turns ratio calculation of the step-up transformer must include the transformer's NLTC or LTC tap settings implemented in operation." **Response:** The drafting team notes that on-load tap changers (OLTC) have time delays which prevent them from responding within the timeframe addressed within this standard and, therefore are not included. The drafting team added discussion in the Guidelines and Technical Basis to improve the clarity that the transformer's taps settings, for certain Options, must be considered. Change made. d) In the Table 1 - Pickup Setting Criteria column, clarify that the rated power factor must be used to calculate the impedance value. Recommend adding the following note under the setting criteria; "Generator rated power factor shall be used to calculate the impedance value". **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. e) In the Table 1 Option 3- Pickup Setting Criteria column, the Reactive Power output determined by the simulation is typically based on the voltage set point at the controlled bus. This can be a moving target if the simulations are done based on different loading

Organization	Yes or No	Question 3 Comment
		conditions. TRE suggests using the generator reactive capability curve (D-Curve) or the actual reactive test data to determine the generator maximum Mvar capability that is to be used for the impedance calculation. **Response:** The drafting team notes that the generator reactive capability curve (D-Curve) describes steady-state capability, not the generator performance during field forcing conditions. No change made. **Response:** The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator Simulation Criteria. Change made. f) In the Table 1 -The Phase Time Overcurrent Relay (51V) voltage-restrained option does not provide specific voltage restraint slope settings to be used. For consistency purpose, voltage restraint slope settings should be included in the pickup setting criteria. **Response:** The drafting team notes this is a coordination issue that is addressed by the existing PRC-001-1 which is proposed to be replaced by PRC-027-1. No change made. g) TRE recommends including generic D-curve, R-X diagrams, voltage-restrained relay curve, and other overcurrent, voltage controlled relay curves in this standard to provide additional clarification. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Southwest Power Pool Reliability Standards Development Team	No	We would suggest that the table be broken up into different tables based on the application of the relay. For example one table for synchronous machines, one table for GSUs, one table for AUX transformers etc..
Response: The drafting team thanks you for your comment and notes that it has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay		

Organization	Yes or No	Question 3 Comment
type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
New York Power Authority	No	Yes for Option 1-16; No for Option 17 as stated in Question 2.
Response: The drafting team thanks you for your comment and has provided a response to New York Power Authority in question 2 above. No change made.		
PPL and Affiliates	No	1. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnection studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #1 above, prepared by the North American Generator Forum (NAGF), comment #3, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #3 below in Question #5. 2. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is also unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition

Organization	Yes or No	Question 3 Comment
		and how hard it is pushed. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #2 above, prepared by the North American Generator Forum (NAGF), comment #4, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #4 below in Question #5. 3. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." The step-by-step calculations wanted can consequently take different paths. Our understanding of what Option 5 requires for example is presented below: -A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. -The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. -The associated MVA at 0.90 PF is 727.778, and the current is 727,778/(18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. -Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT(655^2 + 982.5^2) or 1180.818 MVA. -The current is 1,180,818/(0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals,

Organization	Yes or No	Question 3 Comment
		ref. “Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio” under the “Generator Bus Voltage” column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #3 above, prepared by the North American Generator Forum (NAGF), comment #5, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #5 below in Question #5. 4. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #4 above, prepared by the North American Generator Forum (NAGF), comment #11, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #11 below in

Organization	Yes or No	Question 3 Comment
		Question #5. 5. PRC-025 appears to prohibit loadability relays from having multiple definite-time setpoints or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of **comment #5 above, dual ANSI** C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand, however. Nor is it evident why existing protection schemes that are effective and appropriate should be banned. ***Drafting team observation:*** *PPL for its comment, #5 above, has removed the non-substantive phrase "the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding" between "however and Nor…" that is found in the NAGF comment #8 in Question #5. Also, the reference to "comment #5 above, dual ANSI…" the drafting team believe it should be #3 to correspond to PPL's comment in this Question.* **Response:** Please refer to drafting team's response to NAGF's comment #8 below in Question #5. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-

Organization	Yes or No	Question 3 Comment
		generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. 6. We suggest that NERC instead put this proposed standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. ***Drafting team observation:*** *PPL removed from the beginning of the paragraph #6, the first sentence, "GOs are thus being asked to sign a blank check" that is found in the NAGF comment #8 in Question #5 and PPL added the word "proposed" in the first sentence.* **Response:** For comments #5 and #6 above, the drafting team notes that PPL and Affiliates has submitted the same comment prepared by the North American Generator Forum (NAGF), comment #8, found in Question #5 with non-substantive deletions and removals as observed. Please refer to drafting team's response to NAGF's comment #8 below for Question #5.
Response: Thank you for your comments, please see the responses provided above.		
Wisconsin Electric Power Company	No	1. The criteria for Device 21 on synchronous generators could be greatly simplified by using the criteria in IEEE C37.102, i.e. the 21 setting must be less than or equal to the impedance corresponding to 200% of the generator MVA rating at the rated power factor angle, or a modified version of this to accommodate lower system voltages. **Response:** The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 2. The multiple descriptions under "Bus Voltage" (see options 1-3, 5-7, etc) cause this criteria to be difficult to understand and to apply. It is not readily apparent what the

Organization	Yes or No	Question 3 Comment
		different Bus Voltage options are attempting to accomplish. Are options 1 and 2 identical except for the voltage magnitude? It is not clear why a voltage of 0.95 pu is referenced in Option 1 when the Guidelines and Technical Basis section states that the criteria in Table 1 is based on 0.85 pu transmission voltage. **Response:** The drafting team notes that both the 0.95 and 0.85 per unit Options are fundamentally based on a system voltage during a disturbance of 0.85 per unit, and represent two different complexities for the resulting calculations for distance relays which are connected to generator bus voltages. Options 1, 5, and 13 (now 1a, 2a, and 7a) present the simplest of available calculations by assuming a 10% voltage drop through the GSU transformer (hence a 0.95 per-unit generator bus voltage), and simply adjusting the system voltage by the GSU turns ratio. Options 2, 6, and 14 (now 1b, 2b, and 7b) provide a more involved, but more precise calculation by establishing the system voltage at 0.85 per unit and evaluating the actual voltage drop through the GSU transformer and representing the actual GSU turns ratio and impedance. Also, the terms "transformer turns ratio and impedance" are not clear as to the intent, and perhaps should be deleted. **Response:** The drafting team notes that many GSUs are operated at off-nominal taps in order to achieve optimal generator performance, the standard specifies that the actual turns ratio of the GSU be used. For example, a GSU connecting an 18 kV generator to a 345 kV system may be actually tapped at 362 kV – 17.1 kV. The GSU impedance is used for the calculation of voltage drop through the GSU. No change made. In the references to "simulation" in options 3, 7, and 15, what specific types of analytical studies are intended here, and what specific generator models are required for them? For these reasons, an approach that is simpler to apply is needed for Table 1. **Response:** The drafting team notes that simulations must represent dynamic performance, and must use a comprehensive generator model that includes accurate excitation system

Organization	Yes or No	Question 3 Comment
		performance. The criterion for the simulations themselves, once an appropriate simulation tool is selected and model developed, is fairly simple, and will be further described within the Guidance and Technical Basis section. A generator output of the maximum gross real power capability at normal system voltage should be used as the initial condition, and system voltage subsequently reduced to 0.85 per unit. The generator performance (within the simulation) is then observed to determine the maximum value of reactive power output. For entities that prefer to use alternate and simpler criteria, Options 1a, 2a, or 7a may be used. No change made. 3. There is a need for a good detailed example calculation for the various options in Table 1. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 4. It may be better to break up Table 1 into separate Tables for Generator, GSU's, and Auxiliary Transformers. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. 5. In Attachment 1, 2nd paragraph: a. Replace "Synchronous generator output pickup setting criteria values" with "Synchronous generator relay setting criteria values" **Response:** The drafting team notes that the criteria only addresses portions of the overall relay setting criteria for synchronous generators. However "output" has been replaced by "relay" in consideration of your comment. No change made. b. We suggest that the setting criteria be based simply on the generator MVA capability and

Organization	Yes or No	Question 3 Comment
		rated power factor, instead of calculating it using the real power rating in MW. **Response:** The drafting team notes that the rated power factor as suggested does not reflect the performance of the generator during field forcing conditions and is therefore not applicable. Please see the Guidelines and Technical Basis for more information. No change made. 6. Some of the terms may be misunderstood and should be clarified. "Generator Bus" is at the terminals of the generator. Suggest using a term such as "System Bus" or "Transmission Bus" or similar to designate the bus to which the GSU transformer high-side terminals are connected to. **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
Ingleside Cogeneration LP	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	
ReliabiltiyFirst	Yes	

4. **Do you agree an Implementation Plan of 48-months to install load-responsive protective relay settings is achievable? If not, provide an alternative with specific rationale for such an alternative period.**

Summary Consideration:

Approximately 22 commenters supported by at least 71 different people that provided comments for question #4. There were only two common comment themes presented in question #4. The implementation period was the majority theme.

The first majority comment theme resulted in a change to the standard.

(1) Only four comments supported by individual entities agreed that a 48-months implementation plan was sufficient time to install settings on load-responsive protective relays. One comment expressed a general dissatisfaction with the implementation period. Resoundingly, more than 15 comments supported by at least 40 entities suggested a 60-month implementation plan or greater. Five comments suggested an 84-month implementation, one comment suggested a 120-month implementation, and two comments recommended a phased approached like other reliability standards. The drafting team considered the varying degree of time periods and approaches; and concluded the most reasonable approach is a two-part implementation plan.

For those load-responsive protective relays determined to <u>need only a setting change, entities</u> must have the setting applied by the end of the 48-month implementation period; and for those load-responsive protective relays determined to <u>require replacement</u> to achieve the reliability goals of the standard, entities must have replacements made and settings applied by the end of the 72-month implementation period. For load-responsive protective relays that become applicable due to an outside event (i.e., regulatory action), entities will have a 48-month implementation period only.

There was one minority comment theme in this question.

(2) A single comment supported by at least eight entities was concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

Organization	Yes or No	Question 4 Comment
ACES Power Marketing Standards Collaborators	No	(1) The implementation plan is unreasonable in the amount of time needed to have generation units comply with the standard, especially with the considerations of having to replace existing protective relays, meeting budgetary concerns, coordination with other entities, the time for procurement, and planning outages to complete the necessary work. We suggest 60 months. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made. (2) As mentioned above, there are overlaps with this standard and the applicability section and implementation plan for PRC-023-2. If a generator was subject to PRC-023-2 as a result of being designated by its Planning Coordinator, it would have the "later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date." The drafting team needs to review the applicable time frames, modify PRC-023-2 and provide a clear and understandable timeline that does not have conflicting standards interfering with its implementation. **Response:** The drafting team notes that PRC-023-2 became mandatory as of July 1, 2012, that the implementation of PRC-023-2 is specifically designed for transmission relay requirements, and it is not within the drafting team's scope of work. The drafting team has framed the implementation period of PRC-025-1 with regard to Generator Owners and the circumstances applicable to operating generation. No change made. (3) We strongly suggest that the drafting team review PRC-023-2's implementation plan for

Organization	Yes or No	Question 4 Comment
		GO/GOPs and modify both standards to avoid overlap, confusion, and as discussed above, double jeopardy. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made.
Response: Thank you for your support and comments, please see the responses provided above.		
American Electric Power	No	Due to the expanded scope of this project and the resulting (proposed) requirements, a significant amount of research and studies may need to be performed in order to properly inventory the existing relays and determine their settings. This is not an automated process, and would require extensive print reviews and field verification. The proposed implementation plan emphasizes the time needed to change the relay settings, but deemphasizes the time and effort required to inventory the relays, determine their current settings, and perform the calculations required to determine the new settings. For entities with a large generating fleet, this phase alone could take four years or more to accomplish. Again, this would include the time and resources necessary to actually make those setting changes in the field. Rather than requiring that all research and implementation be completed within 48 months, a time period much too short to perform the work necessary to meet the requirement, AEP believes this standard should instead utilize the precedent of a phased-in approach over 10 years (for example, 50% complete in 4 years, 75% in 7 years and 100% in 10 years).In addition, the work required for this project requires a specific expertise held by a limited number of subject matter experts, and who are also needed to implement other NERC standards and support ongoing reliability efforts. This further supports the need to extend the time allotted beyond four years.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be		

Organization	Yes or No	Question 4 Comment
completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Indiana Municipal Power Agency	No	IMPA recommends using a phased-in Implementation Plan. Generator Owners will have to review current settings and based on this analysis they may have to replace some relays and/or coordinate these relay settings with their Transmission Owner. If relay replacement is required, Generator Owners will have to budget for the new relays. If settings need to be changed, the Generator Owner(s) will need to verify relay settings with the Generator Manufacturer to ensure there are no warranty/safety concerns associated with the relay setting changes. IMPA recommends a 50% completion in 48 months and a 100% completion in 72 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Duke Energy	No	Implementation should be aligned with other similar standards, such as PRC-024, or even extended based on the number of simulations and relay replacements that will be required.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Northeast Power Coordinating Council	No	In the case where existing protective relay replacement may be necessary, 48 months does not provide adequate time to budget, design, coordinate, procure materials, and schedule the work that would have to be done during outage of sufficient duration. Suggest

Organization	Yes or No	Question 4 Comment
		extending the Implementation Plan duration to 60 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Dominion	No	In the case where existing protective relay replacement may be necessary, Dominion does not feel that 48 months provides adequate time to budget, design, coordinate, procure materials, and schedule the work in an outage of sufficient duration. Dominion suggests that 60 months may be more appropriate in this instance.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Ameren	No	Please allow 60 months to implement if indeed protection system equipment or schemes must be changed to comply with R1. More than 48 months will regularly be needed to budget, design, procure materials, obtain construction outages, install and commission such protection system equipment changes.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Tennessee Valley	No	Recommend a schedule that will coincide with the protective relay requirements stated in

Organization	Yes or No	Question 4 Comment
Authority		the revised NERC, PRC-005-2, Protection System Maintenance standard. The protective relays requirements within PRC-025-1 should coincide with PRC-005 in order to maximize benefit of maintenance to satisfy these two standards and to minimize resources necessary to perform the relay settings calculations and installations required by PRC-025-1, if the relay settings need to be revised from current PRC-005 settings. Recommend both implementation plans should be a minimum of 72 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Ingleside Cogeneration LP	No	Similar to PRC-024-1, ICLP believes there needs to be an allowance for those equipment types which cannot accommodate the Table 1 settings. In particular, the variation in the ancillary systems which support the generator is significant - and 48 months will not be sufficient to address every situation.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Detroit Edison	No	Suggest that allowing 72 months to become 100% compliant would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of		

Organization	Yes or No	Question 4 Comment
the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
South Carolina Electric and Gas	No	The 48 month time period may not allow enough time to engineer and then schedule the work necessary to implement the changes. The work required to implement new relaying schemes may be intensive if new relays need to be installed. This type of work requires extended outages that may not occur on an annual or even bi-annual basis. The implementation plan should be modified to at least 60 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Southern Company	No	The implementation plan for execution of Requirement R1, as written, is too short. This requirement will cause GOs to have to check calculations for every relay in the scope of Table 1 for all of its facilities. Checking the setting limits agains the equipment safety levels will take significant time. Equipment procurement, where necessary, and unit outage availability will dictate the exact time required to address the scope of the applicability. It is recommended that the implementation time be increased to 7 years.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Texas Reliability Entity	No	TRE thinks that the implementation plan is too long and we suggest 24 months.

Organization	Yes or No	Question 4 Comment
Response: The drafting team believes in consideration of generator refueling, outage planning, analysis, maintenance cycles, budgeting, and potential protective equipment replacement that the 24 months as proposed is not adequate to allow entities time to become compliant with the standard. No change made.		
PPL and Affiliates	No	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, “while maintaining reliable protection,” aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC-registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. ***Drafting team observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment prepared by the North American Generator Forum (NAGF), comment #1, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #1 below in Question #5. 2. It is additionally not unusual for baseloaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future **due to changing economic conditions**. ***Drafting team observation:*** *The drafting team notes that PPL and Affiliates has submitted a modification to the comment prepared by the North American Generator Forum (NAGF), comment #1, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #1 below in Question #5.
Response: Thank you for your support and comments, please see the responses provided above.		

Organization	Yes or No	Question 4 Comment
Wisconsin Electric Power Company	No	48 months may be achievable for utility generation, but perhaps not for merchant plans. A timeframe of 72 months is suggested. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Manitoba Hydro	Yes	Although we agree with the implementation plan, the Applicable Entities should match the language in the standard i.e. Generator Owners 'that applies....' The language in the Implementation Plan section is awkward in that they refer to 'protective relays applicable to this standard' when it would seem to make more sense to refer to 'protective relays to which this standard applies'.
Response: The drafting team thanks you for your support and comment and has added a note to direct the reader to the standard for further information. The implementation plan is only intended to list the applicable entities as a reference and that the standard is the governing document for the full Applicability for function entities and Facilities. Change made.		
Los Angeles Department of Water and Power	Yes	LADWP agrees the Implementation Plan to install load-responsive protective relay settings is achievable in 48 months.
Response: The drafting team thanks you for your support and comment.		
ATCO Power	Yes	NOT APPLICABLE IN MY JURISDICTION
Response: The drafting team thanks you for your support and comment.		

Organization	Yes or No	Question 4 Comment
Operational Compliance	Yes	We agree with the Implementation Plan of 48 months, but might like to see this time period broken into smaller phases.
Response: The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc. & Affiliates	Yes	
MRO NSRF	Yes	
Luminant	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
Tacoma Power	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 4 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
ReliabiltiyFirst	Yes	

5. **Do you have any other comments? If so, please provide suggested changes and rationale.**

Summary Consideration:

Approximately 19 commenters representing about 37 entities provided general comments for question #5 many of which were raised in the previous four questions. There were at least 24 varying themes supported by nine or fewer entities all of which were minority issues with regard to question 5. Some comments raised in the previous four questions above may have been majority comments for one of these other questions; therefore, the drafting team encourages the reader to review those summaries and responses as well.

Two-thirds of the 25 varying minority themes did not result in changes to the standard. All of these comments were addressed in the previous four questions by the drafting team. One-third of the 24 varying minority themes resulted in changes of varying levels to the standard. Those changes include the following seven items. (1) The drafting team did not post the VSLs in the draft 1 posting, but have provided them for the draft 2 posting. One commenter suggested the VSL should be based on MWh as a method to gradate the VSL; however, the drafting team did not see this as a suitable approach. (2) There were concerns about the Applicability section of the standard. The drafting team made changes to more clearly identify the BES Facilities and the equipment that is included and that the standard applies to load-responsive protective relays. (3) The drafting team received numerous suggestions in the previous questions above to clarify the Attachment 1, Table 1. The drafting team restructured Table 1 for clarity. (4) One comment suggested using “apply” rather than “install” in Requirement R1. The drafting team agreed and made the change based on other comments above. (5) One commenter provided suggestions to revise the Purpose statement. The drafting team agreed to most of the suggestion and made clarifying edits as to the purpose of the standard. (6) A single commenter suggested adding examples to the Guidelines and Technical Basis. The drafting team added additional Guidelines and Technical Basis text and examples based on other comments above.

Organization	Question 5 Comment
Manitoba Hydro	(1) Regarding “Applicability”, it is not clear what type of auxiliary transformers should be included as the “Applicable Facilities”. For example, if the auxiliary transformer is NOT the only supply to the generator, does the standard still apply to this auxiliary transformer? **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying “running power” to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends

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	that the related load-responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. (2) On page 7 of 22, the following sentence is unclear: “Synchronous generator output pickup setting criteria values are determined by the unit’s maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit’s Reactive Power capability, in Megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit’s nameplate megavoltampere (MVA) at rated power factor”. Manitoba Hydro suggests rewording this sentence for clarification. Additionally, should “rated MW” be changed to “rated MVAR’? **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. (3) On page 3, A Introduction, Purpose: We find the purpose quite poorly worded as it stands. It is written in absolutes (i.e. generators do not trip, disturbances that are not damaging) which is quite different than the wording used in the Background to describe the standards (i.e. that did not apparently pose a direct risk). It would seem more appropriate to use language that discusses the purpose as opposed to the outcome. For example, language similar to “To set load responsive generator protective relays at a level designed to prevent tripping of generators during system disturbances that do not apparently pose a direct risk to the generator in order to prevent the unnecessary removal of the generator from service.’ **Response:** The drafting team applied most of the suggestion to the purposed statement; however, the use of “apparently” is more correct as used in the Background section because it refers to conclusions drawn from the analysis of major disturbances. Change made.

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	(4) On page 3, A Introduction, Applicability, 3.1.1: The standard uses the term Generator Owner in terms of functional entities. However, the definition of Generator Owner only makes reference to owner of generating units. Does that still work with 3.2.2 and 3.2.3 which includes Elements other than generating units? **Response:** The drafting team notes that the Functional Model definition for "Generator Owner" is an entity that owns generating units. However, the Applicability section identifies the condition for applicability for a Generator Owner and then identifies the "Facilities" to which the Generator Owner must comply with the standard for the items that apply load-responsive protective relays. No change made. (5) On page 3, A Introduction, Background: Does this 'Background' section become part of the standard once finalized? **Response:** The drafting team notes that the numbered sections within the standard remain upon industry approval. No change made. (6) Attachment A: The opening line should refer to each Generator Owner that applies load-responsive protective relays on the Facilities listed in 3.2 in order to be consistent with the applicability section of the standard itself. **Response:** The drafting team has added the additional reference text for clarification. Change made. (7) Revisions or Retirements to Already Approved Standards: There is a reference to Order NO. 733, paragraph 102. We believe that this needs some elaboration because we are not sure that paragraph sets out the requirement that is in the standard. **Response:** The drafting team apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made.
Response: Thank you for your support and comments, please see the responses provided above.	
ACES Power Marketing Standards Collaborators	(1) We have concerns with the drafting team's approach of requiring replacement of legacy relays for the sake of complying with its proposed standard. This additional strain on resources will have an adverse impact for smaller entities. Smaller entities do not have unlimited budgets and it is

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	difficult to justify the replacement of working equipment just to comply with a regulation. The regulators need to consider reevaluating the threshold that is needed to comply with this standard. If a protection relay is not broken, there should not be a reason to replace it. There is not sufficient justification that having a modern advanced-technology relay with extra functionalities to have a reliability benefit that is commensurate with the cost. **Response:** The drafting team has developed the standard in accordance with the regulatory directives concerning generator relay loadability. The directives are an outcome of the 2003 blackout report and revealed the need to improve generator relay loadability. The goal of the standard is to provide a conservative margin based on generation unit output for which each Generator Owner shall set its load-responsive protective relays. No change made. The drafting team notes that per the 'Power Plant and Transmission System Coordination' – July 2010 – The total number of generators that tripped in the 2003 blackout is 290; eight of those by phase distance and 20 more by 51V protection. Additionally, the cause of tripping for 96 generators is unknown, either because the generator failed to respond to data requests or because the Generator Owner was not able to determine the cause. No change made. (2) We suggest the drafting team complete the VSL table and provide a draft RSAW of this standard. PRC-023-2 is currently in effect and there is no guidance or RSAW posted, which results in a tremendous amount of confusion on how to comply with the standard. We strongly suggest that the SDT plan for how the industry will need to comply with PRC-025-1 and provide a sample RSAW. Also, if this standard is results-based, then is it possible to consider internal controls for the responsible entity to correct relay settings without consequences of self reporting? **Response:** The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website. The drafting team notes that the standard PRC-023-2 RSAW (11/15/2012) is currently posted on the NERC website under the Compliance tab. The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps

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	in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change **made.** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. (3) We disagree with the setting of a high VRF for Requirement R1. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with the NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. A Medium VRF is more appropriate. **Response:** The drafting team notes that the circumstances around the August 14, 2003 blackout were exacerbated by the loss of generation. Applying a Violation Risk Factor (VRF) of Medium would be inconsistent with the NERC definition. Failure to apply the settings could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition; therefore, a VRF of High has been selected. This VRF is also consistent with the approved version of PRC-023-2 - Transmission Relay Loadability standard. No change made. (4) We disagree with the statement "that it may be necessary to replace the legacy relay with a modern advanced-technology" on page 14 in the Guidelines and Technical Basis section. Section 215(i)(2) is very clear that the ERO or Commission are not authorized to order construction. Thus, a standard cannot compel relay replacement. **Response:** The drafting team notes that Section 215 (i)(2) of the Federal Power Act states: "This section does not authorize the ERO or the Commission to order the construction of

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	additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." This clause pertains to the construction of additional generation or transmission capacity and not the modification, replacement, or installation of a relay that may be necessary to meet the reliability goal of a standard. No change made. (5) There is text in the comment form regarding using a Method 1 or Method 2 for relay loadability. We can find no mention of these methods in the standard or Guidelines and Technical Basis. The methods actually require calculating loadability at two operating points. While one of the points appears to be Pick-up Setting Criteria in Table 1 of Attachment 1, the other is not referenced anywhere in the standard. Please include this section in the standard as appropriate or remove it from the comment form as its purpose is very confusing. **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made. (6) Thank you for the opportunity to comment.
Response: Thank you for your comments, please see the responses provided above.	
Essential Power, LLC	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot

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	could be cast. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition and how hard it is pushed. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "...a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set

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	under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio" under the "Generator Bus Voltage" column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core

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	clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. 8. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade

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	rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "...while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. 9. The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." It should be replaced by the term "generator bus or high side-to-medium voltage," as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated

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	any economic rationale for having black-start facilities. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. 13. Using the term “apply settings” rather than “install settings” in Requirement R1 better suits the accepted terminology for setting the protective device parameters. 14. The phrase “while maintaining reliable protection” in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with “achieving ...desired protection goals”. In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity’s existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection

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	used by many companies has proven (over multiple decades) to be adequate for protecting equipment and providing reliable power supply to customers.
Response: The drafting team thanks you for your comments and notes that Essential Power, LLC has submitted the same comments prepared by the North American Generator Forum (NAGF). Please see the responses to these comments below in the response to the North American Generator Forum comments for Question #5.	
Tennessee Valley Authority	1. There is a strong relationship between this reliability standard, PRC-025-1, Generator Relay Loadability, and PRC-005-2, Protection System Maintenance, regarding the testing, maintenance, and installing the settings on the same protective system relays. To ensure PRC-025 and PRC-005 are in sync with each other, recommend each be referenced in the "F. Associated Documents" of the other. **Response:** The drafting team does not believe referencing another standard in Section "F" achieves more clarity or provides additional benefit to the standard; however, the documents already named in the standard will be added here as they are relative to the standard. Change made. 2. Recommend PRC-025-1 relay settings be recalculated at a frequency that coincides with PRC-005-2, Protection System Maintenance, performance frequencies found in the PRC-005-2, respective tables. The standard should also allow the generator owner to determine for their own applications whether the on-going repetitive calibrations and functional testing should be time based, performance based, or a combination of the two, in accordance with PRC-005-2. **Response:** The drafting team understands the logic suggested here. Each standard must stand on its own. The standard does not preclude the Generator Owner from creating its own internal control over PRC-025-1 based on PRC-005-2 activities; however, the drafting team has modified the implementation plan to which should allow the Generator Owner to align its activities. Once the relays are set, there is no reason to perform on-going repetitive calibrations and functional testing as a part of PRC-025-1. Change made to the implementation plan.
Response: Thank you for your comments, please see the responses provided above.	

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American Electric Power	Are transformers which are independent of the generator bus, and are fed from the grid, in scope? Figure 1 seems to infer the inclusion of such devices, but if so, that is not made explicit within the description provided in 3.2.3 and Note 1. Both 3.2.3 and Note 1 need to be more specific or refer to an attachment for examples. **Response:** The drafting team refers to the footnote in the Applicability (footnote 1). The connection is not relevant. Also, the drafting team provided in the posted draft 1 standard, figures that illustrate this condition. No change made. This standard does not explicitly state which auxiliary transformers are in scope. AEP recommends clearly identifying whether the standard is applicable to Reserve Auxiliary Transformers. In addition, Footnote 1's second sentence should be modified to state "Loss of these transformers will result in the generator's immediate removal from service."The scope of this draft is inconsistent with the title and purpose with respect to generator protective relays as opposed to generation relays. The phrase "generator relay" has a specific meaning to a relay engineer, and encompasses only a subset of the generation relays covered under this standard. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Idaho Power Company	Based on the language of Section 3.2.3, which describes the applicable facilities, we believe some addtional clarification should be added to Footnote 1. Many modern static excitation systems have a sizable dedicated transformer. We believe a mention of these excitation transformers would provide needed clarification.
Response: The drafting team notes that the concerns raised relative to relays on an Exciter PPT and ISO Phase Bus between the	

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generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up (GSU) transformer, unit auxiliary transformers (UAT), and lines are within the scope of the standard. No change made.	
Los Angeles Department of Water and Power	For the Transmission Relay Loadabiltiy Program, examples and job aids were provided to establish a uniform method to calculate relay settings. Examples and job aids should also be included for Generator Relay Loadability.
Response: The drafting team thanks you for your comment and has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.	
ATCO Power	Get rid of the 150% assumption. It can be calculated directly from transformer impedance. Get rid of the special cases -- there are too many, such as load tap changers, that you are not handling. Simply require that generators' 21 relays be set to ride through the consequences of a 0.85% transmission voltage depression with 115% fudge factor, and specify the loading range you care about for special cases. This works out to a mho circle, diameter=Xt/(0.15 * 1.15), MTA=90 degrees, zero offset. Compliance verification is a straightforward engineering exercise.
Response: Thank you for your comments, the drafting team has added clarification of the timeframe the standard is addressing to the Guidelines and Technical Basis. The timeframe of concern is during field forcing which precludes the calculations described in your above comment. Therefore, it is necessary to use an approximation based on observed data or a simulation as described in the standard. The drafting team added the special cases (Options) to allow the entity to use the simplest calculation to the more involved and precise calculations or simulation. The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.	
Ingleside Cogeneration LP	ICLP believes that NERC's Compliance organization should be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the

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	standards for exactly this reason.
Response: The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website.	
Tacoma Power	Referring to the first paragraph of Attachment 1, Options 1-17 are not truly exclusive options. Options 1-3, Options 5-7, Options 10 & 11, and Options 13-15 each appear to be exclusive options. However, an entity may, for example, need to apply Options 1, 2 or 3 together with Options 10 or 11 together with Option 17. Consider separating Table 1 into multiple tables, each table based upon a different combination of relay type and application. Each option within each table would then be exclusive.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.	
Southwest Power Pool Regional Entity	Since this standard isn't enforceable until 48 months after approval, why not make the effective date 48 months after approval? This would reduce confusion concerning Registered Entities' requirements for performance (such as outage scheduling and early adoption) during the 48 month implementation period.
Response: The drafting team thanks you for your comment and notes that the standard's effective date begins with an implementation plan based on the effective date. Using this structure places the standard in effect and requires the Generator Owner to apply the required settings based on the implementation plan period. No change made.	
Independent Electricity System Operator	The proposed effective date in the implementation plan may not clearly address a potential conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that the sentence be re-arranged as follows: [First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory

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	approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees.]
Response: The drafting team thanks you for your comment and notes that the effective date language has been vetted by NERC Legal staff and provided as standard language for reliability standards. The current language is clear in the first sentence that for United States entities, the Federal Energy Regulatory Commission or FERC (i.e., "applicable regulatory authorities") and for Canadian entities (or others) the first sentence means its applicable regulatory authority. The second clause is for those entities (registered with NERC) which are not governed by a regulatory body, the standard becomes effective upon NERC Board of Trustees approval. No change made. For a better understanding of the suggestion, the drafting team has formatted the suggestion from above with respect to the approved template language provided in reliability standards. For reference only: **Reference**: First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees. ~~or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~	
pacificorp	The use of the term "Bulk Electric System generation Facilities" in the Applicability Section 3.2 of the standard is not explicitly defined. PacifiCorp recommends that the Standards Drafting Team include generator size to further refine the applicability of facilities under this standard.
Response: The drafting team thanks you for your comment and notes that the use of Bulk Electric System defines what Facilities are applicable to the standard. The team has utilized this definition because it is a NERC defined term and is also undergoing improvements and exclusions. The NERC registration criteria define the minimum sizes that require an entity to register as a Generation Owner. Also, this standard does not provide any exclusion based on physical factors (i.e., size or voltage connection) on the basis of information which demonstrated that generators of all sizes, when connected, play a role in maintaining reliability during Transmission system disturbances; therefore, the team believes that defining the applicability provides no additional reliability benefit. No change made.	
Nebraska Public Power District	We have seen many interpretations of the calculations for Table 1 during industry forums. Examples

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	need to be provided.
Response: The drafting team thanks you for your comment and has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.	
Ameren	Yes. (1) Applicability should be consistent with PRC-023-2 (generators connected at 200kV and above, etc.). **Response:** The drafting team notes that the use of Bulk Electric System defines what Facilities are applicable to the standard. The team has utilized this definition because it is a NERC defined term and is also undergoing improvements and exclusions. The NERC registration criteria define the minimum sizes that require an entity to register as a Generation Owner. Also, this standard does not provide any exclusion based on physical factors (i.e., size or voltage connection) on the basis of information which demonstrated that generators of all sizes, when connected, play a role in maintaining reliability during Transmission system disturbances; therefore, the team believes that defining the applicability provides no additional reliability benefit. No change made. (2) System connected auxiliary transformers should be excluded. This is consistent with the industry's determination in PRC-005-2, which has now passed recirculation ballot. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. (3) VSLs are listed as 'to be determined'. We recommend that severity be risk-based by relating it to the % of MWh the generator in violation has provided during the period of violation (i.e. % of GO entity's total MWh production.)

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	Response: The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. The drafting team also notes that a VSL cannot be based on availability. If a generator is online, it is expected under the premise of the standard to remain connected during the conditions discussed in the standard. The VSLs are based on a per violation per day basis for not complying with the standard. The drafting team has constructed the VSLs consistent with the NERC VSL Guidelines. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Southern Company	Yes. In Applicability Section 3.2, we disagree with the specifier "including those identified as Blackstart Resources in the TOP's system restoration plan". The additional small units this may draw in to the scope of this standard are not large enough to be significant contributors to correcting frequency and voltage perturbations on the transmission network. **Response:** The drafting team believes that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP), if identified as being BES. No change made. The word "overall" does not add any value to applicability section 3.2.3. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers

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	(UAT) to trip and in turn cause the generator to trip. No change made. If the voltage restrained overcurrent relay is the primary relay of concern (as noted from the 14 Aug 2003 disturbance), perhaps the solution is to require that they are replaced with alternative types of relaying rather than by specifying the desensitizing setting specifications. **Response:** The drafting team notes that a number of load-responsive protective relays operated during the August 14, 2003 blackout that were contributory to the expanse and spread of the outage. The regulatory directive from Order No. 733 that the team is addressing identifies load-responsive phase protection relays as the protective function concerning loadability. No change made. We have real, historical cases where a generator back-up overcurrent relays set at 115 to 130% of the unit rating have saved the units that were exposed to either a low-level, close transmission faults or excitation system malfunctions. A possible solution to generator relaying modifications to provide the maximum allowable loadability for supporting system disturbance events may be to remove all voltage restrained/controlled overcurrent relays and replace them with a standard 51 function. This relay could be set just under the generator ANSI overload curve to protect the unit from low level overload. This would give plenty of area for swings while still protecting the generator. The 21 function could then be adjusted to pickup at 180 to 200% of the units MVA rating with appropriate time delay to coordinate with transmission Zone 3 relays. An alternative solution to specifying the generator relay settings is to allow the PRC-001 standard (currently under draft) to take care of the desired coordination between generator relaying and transmission system relaying. In that standard, the GO and TO must confer with one another regarding the coordination of the generator relaying and the transmission system relaying. The loadability issue of generators, we believe, can be adequately resolved by the coordination requirements to be contained in PRC-001. **Response:** The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) <u>may</u> no longer be able to achieve the

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	desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.	
North American Generator Forum (NAGF)	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration

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	in excess of 72 months would be excessive. Change made. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot could be cast. **Response:** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. **Response:** The drafting team notes that the Mvar capability in the standard is not directly obtained from the steady state capability curve. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. This Mvar value is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor. Simulations and actual disturbances show that the value of the maximum Mvar is approximately equal to 150% of the derived nameplate MW value. Refer to Guidelines and Technical Basis within the standard for more information on field forcing. No change made. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition and how hard it is pushed. **Response:** The drafting team notes that Attachment 1 has been revised to add "capability" reported

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	to the Planning Coordinator or Transmission Planner. If the gross MW capability reported to the Planning Coordinator or Transmission Planner varies seasonally, the drafting team intends that the highest of the various seasonal capabilities be used by the Generator Owner. If from year to year the capability for any specific season varies the entity may need to reevaluate their protection if the newest maximum gross MW capability has increased from that previously used. The drafting team does not anticipate that entities will unnecessarily change settings if the maximum gross MW capability decreases. Change made. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio" under the "Generator Bus Voltage" column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7%

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	overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however.

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	Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists.

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	Response: The drafting team notes that the standard does not require that the generator achieve the Mvar capability during conditions anticipated by the standard, but instead that the load-responsive protective relays accommodate whatever field forcing may occur during disturbances. Actual observed generator performance during disturbances, as well as numerous simulations using actual generator data, have shown that many generators may approach this value of field forcing. The drafting team understands that not all generators will be able to achieve this performance , and has offered the opportunity to perform simulations with specified criteria in order to determine the expected performance of a specific generator and application in order that the load- responsive protective relays may be set in a manner more precisely representative of that generator's performance. Therefore, an additional exception process is not warranted. The drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. Additionally, the overall "load" current represented by the criteria within this standard is approximately 200% of the continuous capability of the GSU transformer, and is well within the transformer capability as established by IEEE C57.109-1993. No change made. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. **Response:** The drafting team notes that the Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing that will occur during abnormal system conditions is not affected by compromised equipment. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. The drafting team does not believe that entities will change settings when the unit is de-rated. No change made.

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	8. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). **Response:** The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made. Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has

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	been modified to "…while maintaining reliable <u>fault</u> protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "it is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. **Response:** The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards. Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. **Response:** The drafting team notes that the drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance

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	expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 9. The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." It should be replaced by the term "generator bus or high side-to-medium voltage," as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team believes that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP), if identified as being BES. No change made. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that

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	dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. **Response:** The drafting team believes that the dynamic performance of individual generators can be simulated by modeling the generator at an output of the maximum gross real power capability at normal system voltage, and subsequently reducing the system voltage to 0.85 per unit. The generator performance (within the simulation) is then observed to determine the maximum value of reactive power output. Change made. The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator Simulation Criteria. Change made. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. **Response:** The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 13. Using the term “apply settings” rather than “install settings” in Requirement R1 better suits the accepted terminology for setting the protective device parameters. **Response:** The drafting team agrees, and has modified the standard as suggested. Change made. 14. The phrase “while maintaining reliable protection” in Requirement R1, as explained in the

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	Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection used by many companies has proven (over multiple decades) to be adequate for protecting equipment and providing reliable power supply to customers. **Response:** The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability.

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	For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Exelon	-Please clarify if the scope of this Standard includes the protection for the leads connecting the high voltage side of the Generator Step up Transformer to the output breakers/buses in the switchyard. If so, what are the protection requirements? If not, which Standard or Standard under development project is intended to cover the protection system for this section? **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. -Table 1 lists the number of options incrementally across all relay types (1-17) rather than grouping options by relay type. It may be clearer to identify the options in groups by relay type. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.
Response: Thank you for your comments, please see the responses provided above.	
PPL and Affiliates	1. The meaning of the word “overall” is unclear in Applicability para. 3.2.3, “Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.” The statement above should be replaced by “Auxiliary transformer(s) that supply HV or generator bus-to-MV transformers supporting auxiliary loads required for the unit to operate.” as it

Organization	Question 5 Comment
	may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. ***Drafting team observation:*** *PPL #1 has made changes to phrases used in NAGF's comment #9 in Question #5 above. The modified comment is noted below for reference.* ***Reference:*** NAGF #9: "The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." **The statement above** ~~**It**~~ should be replaced by ~~**the term "generator bus or high side-to-medium voltage,"**~~ **Auxiliary transformer(s) that supply HV or generator bus-to-MV transformers supporting auxiliary loads required for the unit to operate** as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change." **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. 2. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due tobeing black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study. Imposing on black start units requirements that are unnecessary for BES reliability will further discourage GOs from building such units. ***Drafting team observation:*** *The last sentence in PPL #2 replaced the following clause in the last sentence of NAGF's comment #10 in Question #5 from, "…study, reasonable coordination study,*

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	rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities.” **Response:** The drafting team notes that PPL and Affiliates has submitted the same comment #2, as that prepared by the North American Generator Forum (NAGF), comment #10, found in Question #5. Please refer to drafting team’s response to NAGF’s comment #10 above. 3. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. **Response:** The drafting team notes that PPL and Affiliates has submitted the same comments #3, as that prepared by the North American Generator Forum (NAGF), comment #7, found in Question #5. Please refer to drafting team’s response to NAGF’s comment #7 above. 4. The currently “To be determined” VSLs should be defined before the standard is voted upon. **Response:** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made.
Response: Thank you for your comments, please see the responses provided above.	

END OF REPORT

Draft 2

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 2 of PRC-025-1, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period with Parallel Initial Ballot	January 2012
30-day Formal Comment Period with Parallel Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive generator protective relays at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damaging the generator.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities.

   3.2. Facilities: The following Elements associated with Bulk Electric System generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Unit auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Generator interconnection Facility(ies).

4. **Background:**

   After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may

[1] These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the Guidelines and Technical Basis for more detailed information concerning auxiliary transformers.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

B. Requirements and Measures

R1. Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

Each Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities shall use one of the following Options 1-19 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator or Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Planning Coordinator or Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples include, but are not limited to, the following:

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions),
- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard, or

- Protection systems that are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Synchronous generators	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase time overcurrent relay (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% o the calculated current derived from: (1) Real Power output – 100% of the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output determined by simulation
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current, derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer – synchronous generators	Phase time overcurrent relay (51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer – synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the connected generation maximum gross Mvar output determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	11a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current, derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		11b	1.0 per unit of the high-side nominal voltage for overcurrent relays installed on the high-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51)	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner
A different application starts below				
Generator interconnection Facilities – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		14b	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities – synchronous generators	Phase time overcurrent relay (51)	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		15b	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% o the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		16b	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
A different application starts below				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft ~~1~~2 of PRC-025-1, Generator Relay Loadability for a ~~30~~45-day formal comment period and initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period with Parallel Initial Ballot	~~December~~January 2012
30-day Formal Comment Period with Parallel Successive Ballot	~~March~~June 2013
Recirculation ballot	~~June~~July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive generator protective relays at a level ~~such that ~~to prevent unnecessary tripping of generators ~~do not trip ~~during a system ~~disturbances~~disturbance for conditions that ~~are~~do not pose a risk of damaging ~~to ~~the generator~~ thereby unnecessarily removing the generator from service~~.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays ~~on~~at the terminals of Facilities listed in 3.2, Facilities.

   3.2. Facilities: The following Elements ~~of the~~associated with Bulk Electric System ~~generation Facilities~~generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 ~~Auxiliary~~Unit auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Generator interconnection Facility(ies).

4. **Background:**

   After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout~~"~~" in the northeastern North American continent.[2]

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[1] These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the Guidelines and Technical Basis for more detailed information concerning auxiliary transformers.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

B. Requirements and Measures

R1. Each Generator Owner shall ~~install~~apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay ~~in accordance with *PRC-025-1 – Attachment 1: Relay Settings*~~, each Generator Owner shall have ~~and provide as~~ evidence~~, dated documentation~~ (e.g., summaries of~~: (1) settings~~ calculations, ~~and (2~~spreadsheets, simulation reports, or setting sheets) that settings were ~~installed~~applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~The Regional Entity shall serve as the Compliance Enforcement Authority (CEA)~~

~~unless the applicable entity is owned, operated, or controlled by the Regional Entity.~~

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the ~~latest~~ last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	~~To be determined~~N/A	~~To be determined~~N/A	~~To be determined~~N/A	~~To be determined~~The Generator Owner did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

PRC-025-1 – Attachment 1: Relay Settings

Introduction

Each Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities shall use one of the following Options 1-~~17~~19 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application~~.~~ and relay type. The bus voltage is ~~determined by~~based on the criteria for the various applications listed in Table 1.

Synchronous generator ~~output~~relay pickup setting criteria values are ~~determined by~~derived from the unit's maximum ~~seasonal~~ gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator~~;~~ or Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the ~~rated~~ MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator ~~output~~relay pickup setting criteria values ~~are determined by~~ (including inverter-based installations) are derived from the site's aggregate maximum ~~seasonal gross Real Power~~ complex power capability, in ~~MW~~MVA, as reported to the Planning Coordinator~~; and the Reactive Power capability, in (Mvar), as determined by calculating the rated Mvars based on the aggregate MVA at rated power factor and adding~~ or Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.~~ Asynchronous~~

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples include, but are not limited to, the following:

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria ~~also include inverter-based installations.~~outlined in the standard,
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions),

- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard, or
- Protection systems that are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Synchronous generators	Phase ~~Distance Relay~~distance relay (21) – ~~D~~directional toward the Transmission ~~S~~system	~~1~~1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of the MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor
		OR		
		~~2~~1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output ~~–~~ 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of the MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor
		OR		
		~~3~~1c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output ~~– a value that equates to~~100% of the ~~Maximum~~maximum gross Mvar output determined by simulation

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	The same application continues on the next page with a different relay type			
Synchronous generators	Phase ~~Time Overcurrent Relay~~time overcurrent relay (51V~~)~~-R) – voltage-restrained	~~5~~2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from ~~115% of~~: (1) Real Power output – 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of the MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor
		OR		
		~~6~~2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from ~~115% of~~: (1) Real Power output – 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of the MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor
		OR		
		~~7~~2c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% o the calculated current derived from ~~115% of~~: (1) Real Power output – 100% of ~~maximum seasonal gross~~the MW capability reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output ~~– a value that equates to Maximum~~ 100% of the maximum gross Mvar output determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	Phase ~~Time Overcurrent Relay (51C) —~~time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage ~~(e.g., Voltage controlled relay~~)	~~9~~3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the ~~nominal~~calculated generator bus voltage
A different application starts on the next page				
Asynchronous generators (including inverter-based installations)	Phase ~~Distance Relay~~distance relay (21) – ~~D~~directional toward the Transmission ~~S~~system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the ~~total~~maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~Time Overcurrent Relay~~time overcurrent relay (51V~~)~~-R) – voltage-restrained	~~8~~5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current, derived from ~~130% of total~~the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
A different application starts on the next page				
Generator step-up transformer – ~~S~~synchronous generators	Phase ~~Distance Relay~~distance relay (21) – ~~D~~directional toward the Transmission ~~S~~system	~~13~~7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of ~~connected~~the aggregate generation MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor
		OR		
		~~14~~7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to 150% of rated MW~~150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
		~~15~~7c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output ~~– a value that equates to the Maximum~~100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer – ~~S~~synchronous generators	Phase ~~Time Overcurrent Relay~~time overcurrent relay (51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		~~10~~8b	Calculated generator bus voltage corresponding to 0.85 per unit ~~of the high-side~~ nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from ~~115% of~~: (1) Real Power output – 100% of ~~connected~~the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of ~~connected~~the aggregate generation MW value, derived from the nameplate MVA rating at rated ~~MW~~power factor

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		OR		
		~~11~~8c	Simulated generator bus voltage corresponding to 0.85 per unit ~~of the high-side~~ nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from ~~115% of~~: (1) Real Power output – 100% of ~~connected~~the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to the Maximum~~100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer – ~~S~~synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		9c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the connected generation maximum gross Mvar output determined by simulation
A different application starts on the next page				
Generator step-up transformer – ~~A~~asynchronous generators only (including inverter-based installations)	Phase ~~Distance Relay~~distance relay (21) – ~~D~~directional toward the Transmission ~~S~~system	~~16~~10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the ~~total~~maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~Time Overcurrent Relay~~time overcurrent relay (51)	~~12~~11a	Generator bus voltage corresponding to 1.0~~.85~~ per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current, derived from ~~130% of~~the maximum aggregate ~~installed maximum rated~~nameplate MVA output ~~of the connected generators~~ at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		11b	1.0 per unit of the high-side nominal voltage for overcurrent relays installed on the high-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				
~~Auxiliary~~Unit auxiliary transformers (UAT)	Phase ~~Time Overcurrent Relay~~time overcurrent relay (51)	~~17~~13a	1.0 per unit of the winding nominal voltage ~~on the high-side terminals~~ of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from ~~150% of the current derived from the~~the unit auxiliary transformer maximum nameplate ~~maximum~~ MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner
A different application starts below				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Generator interconnection Facilities – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		14b	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
	The same application continues on the next page with a different relay type			
Generator interconnection Facilities – synchronous generators	Phase time overcurrent relay (51)	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		15b	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% o the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		16b	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation
A different application starts below				
Generator interconnection Facilities – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The implementation plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance the standard. The period to become compliant is based on two conditions. One time frame is provided if the Generator Owner determines that its existing load-responsive protective relays are capable of achieving the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner determines that its existing load-responsive protective relays require replacement. The drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The implementation plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The implementation plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner will need to evaluate load-responsive protective relays applied on its Facilities, perform the applicable calculations required by the standard, and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.

Applicable Entities

- Generator Owner*

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

- None.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant for the following:

- For each load-responsive protective relay, where determined by the Generator Owner that replacement is not necessary, 48 months beyond the effective date of this standard.
- For each load-responsive protective relay, where determined by the Generator Owner that replacement is necessary, 72 months beyond the effective date of this standard.

Load-responsive protective relays which become applicable to the standard

The Generator Owner owning load-responsive protective relays that become applicable to this standard, not because of the actions of the Generator Owner including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the first day of the first calendar quarter that is 48 months beyond the date such change is effected by an applicable regulatory authority, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1** **R1.** Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [Violation Risk Factor: High] [Time Horizon: Long-Term Planning*]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Relay Loadability: Generator.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan
Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The implementation plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance the standard. The period to become compliant is based on two conditions. One time frame is provided if the Generator Owner determines that its existing load-responsive protective relays are capable of achieving the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner determines that its existing load-responsive protective relays require replacement. The drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment.

<u>General Considerations</u>

The Implementation Plan period reflects consideration of the following:

~~1. The Generator Owner will likely find it necessary to adjust the existing load responsive protective relay settings on its generation unit(s) to comply with this standard, and it will be necessary for the plant to be off-line in order to make these adjustments.~~

~~2. The Generator Owner may find it necessary to replace portions of their existing protective relaying in order to comply with this standard. In such cases, the Generator Owner may need to budget the necessary work, engineer the necessary adjustments, coordinate with other entities, and procure certain materials. Further, the Generator Owner may require an outage of significant duration in order to apply settings, perform necessary testing, and replace any necessary components.~~

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit <u>or plant</u> from service solely to achieve compliance with this standard.

~~3.~~1. <u>The</u> ~~Additionally, the~~ implementation <u>plan</u> recognizes that the time between scheduled outages depends on the nature of the generation <u>unit or</u> plant and may be as long as 24 months~~. Due to the time~~ between scheduled outages~~, the implementation plan also considers the time required to budget and procure the necessary material; therefore, provides a 48-month period for becoming 100% compliant with the standard~~.

~~4.~~ <u>The</u> ~~For a Generator Owner with a sizable generation fleet, the~~ implementation plan <u>assumes that Generator Owners will stagger</u>~~provides time for staggered~~ outages <u>between generation units or plants</u>~~.~~

~~General Considerations~~

~~To be developed in draft 2~~ based <u>upon fleet size, operating history, and forecasted outages</u>~~on industry comment~~.

2. <u>The Generator Owner will need to evaluate load-responsive protective relays applied on its Facilities, perform the applicable calculations required by the standard, and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.</u>
3. <u>It is necessary for the generation unit or plant to be off-line in order to make adjustments.</u>
4. <u>The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.</u>
5. <u>For those load-responsive protective relays that do not require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard and schedule the work while the generation unit or plant is off-line.</u>

6. For those load-responsive protective relays that require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.

Applicable Entities

- Generator Owner*

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

None.~~N/A~~

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load -responsive protective relays subject to the standard

Each~~The~~ Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant for the following:~~48 months beyond the effective date of this standard.~~

- For each load-responsive protective relay, where determined by the Generator Owner that replacement is not necessary, 48 months beyond the effective date of this standard.
- For each load-responsive protective relay, where determined by the Generator Owner that replacement is necessary, 72 months beyond the effective date of this standard.

Load -responsive protective relays which become applicable to the standard

The Generator Owner owning~~that owns~~ load -responsive protective relays that become applicable to this standard, ~~(~~not because of the actions of the Generator Owner including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action,~~),~~ shall be 100% compliant on the first day of the first calendar quarter that is 48 months beyond the date such change is effected by an applicable regulatory authority, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1** **R1.** Each Generator Owner shall apply~~install~~ settings that are in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Relay Loadability: Generator~~102~~.	

Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The term, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner ("responsible entity") is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generation unit or plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the responsible entity consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be necessary to replace the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the responsible entity must understand the applications of Table 1, Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

The drafting team recognizes that some Generator Owners own an interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") between the generator and the interface with the portion of the BES where Transmission Owners take over the ownership. In these cases, the Generator Owners own sole-use Facilities that are connected to the boundary of the interconnected system. Load-responsive protective relays applied by the Generator Owner at the terminals of these Facilities to protect these interconnection Facilities are included in the scope of this standard.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column “Pickup Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the generator step-up transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (0.95 per unit) and 1b (0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (simulation) was developed to allow the responsible entity to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19), for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The responsible entity who elects to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in megawatts as reported to the Planning Coordinator or Transmission Planner.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with*

little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may restrict the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays are similar. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in these options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer

(excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers.

Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side or high-side of the generator step-up transformer of a synchronous generator.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the

Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Options 11a and 11b)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11a, address those generator step-up transformer phase time overcurrent relays installed on the low-side (i.e., generator-side) of the generator step-up transformer of an asynchronous generator, and Option 11b addresses those relays installed on the high-side (i.e., line-side) of the generator step-up transformer of an asynchronous generator.

Option 11a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer for overcurrent relays installed on the low-side. The voltage drop across the generator step-up transformer is calculated based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio of the generator step-up transformer. This is a simple calculation that approximates the stressed system conditions.

Where the relay current is supplied from the generator bus, Option 11a, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio. Where the relay current is supplied from the high-side of the transformer, it is necessary to assess loadability using the high-side nominal voltage in Option 11b.

For Options 11a and 11b, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Option 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) ("UAT")that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying protecting UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relaying applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are not a part of this standard. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating unit or plant.

Refer to the figures below for example configurations:

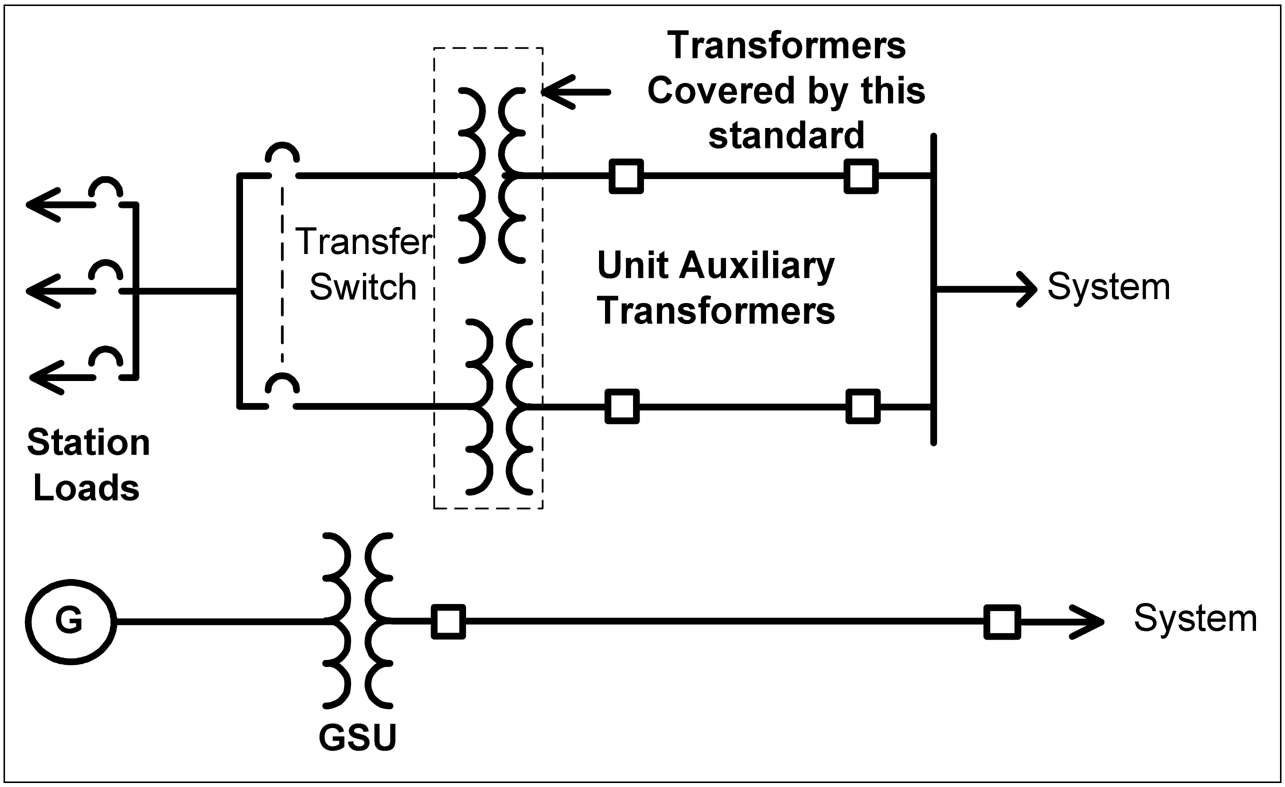

Figure-1 – Auxiliary Power System (independent from generator)

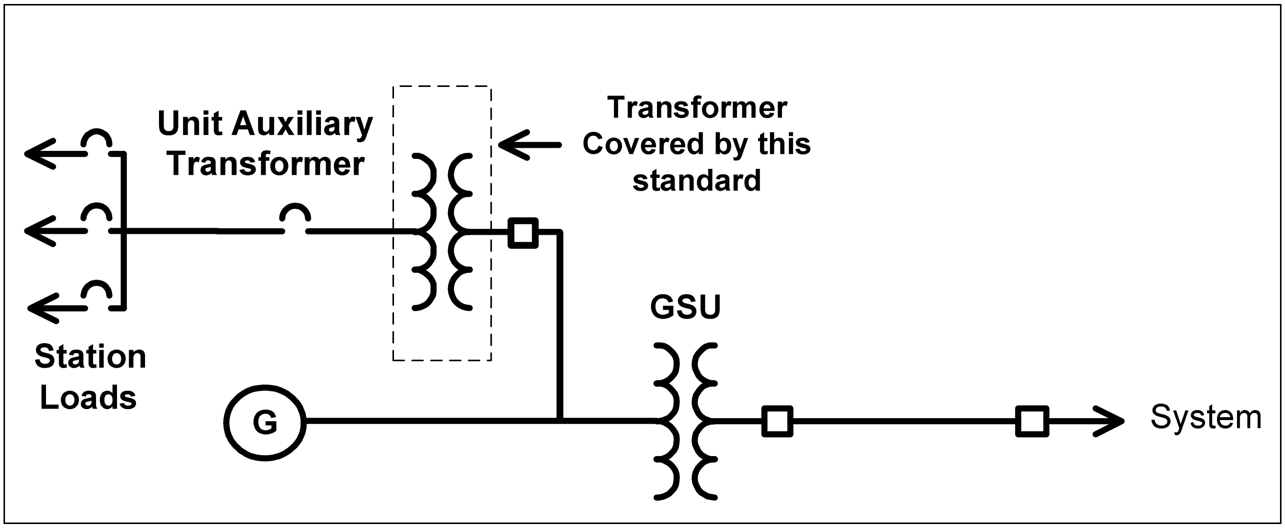

Figure-2 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected UAT load demand at the highest generator output. Although the MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

The performance of the UAT loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 14a and 14b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator step-up transformer phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Option 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 15a and 15b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 16a and 16b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Generator nameplate (MVA @ rated pf):	$GEN_{nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen} = 22\ kV$
Real Power output in MW as reported to the PC or TP:	$P_{reported} = 767.6\ MW$
Generator step-up transformer impedance (903 MVA base):	$Z_{gsu} = 12.14\%$
Generator step-up transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer ratio:	$PT_{ratio} = \frac{200}{1}$
Auxiliary transformer nameplate:	$UAT_{nameplate} = 60\ MVA$
Auxiliary low-side voltage:	$V_{uat} = 13.8\ kV$
Auxiliary current transformer:	$CT_{uat} = \frac{5000}{5}$
Transformer High Voltage CT:	$CT_{HV} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 100\ Mvar$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{namplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{reported} + jQ$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 0.3130\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

Example Calculations: Option 1a

$$Z_{sec} = 0.3130\angle 56.3°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3130\angle 56.3°\ \Omega \times 25$$

$$Z_{sec} = 7.8238\angle 56.3°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{7.8238\angle 56.3°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.8033\angle 56.3°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.8033\ \Omega}{\cos(85.0° - 56.3°)}$$

$$Z_{max} < \frac{6.8033\ \Omega}{0.8771}$$

$$Z_{max} < 7.7561\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance (21) directional toward the Transmission system relay. This option requires calculating low-side voltage taking into account voltage drop across the generator step-up transformer. Similarly these calculations may be applied to Option 7b for generator step-up transformers applying a phase distance (21) directional toward the Transmission system relay.

Real Power output (P):

Eq. (9) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P}{MVA_{base}}$$

$$P_{pu} = \frac{767.6\ MW}{767.6\ MVA}$$

$$P_{pu} = 1.0\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low\text{-}side}$ converges:

Eq. (14) $$\theta_{low-side} = \frac{\sin^{-1}\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

$$\theta_{low-side} = 7.3°$$

Eq. (15) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9981 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8484}$$

$$\theta_{low-side} = 7.0°$$

Eq. (17) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987\ p.u.$$

Example Calculations: Options 1b and 7b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9987\ p.u.\ \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.88\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°$$

Primary Impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.88\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 0.3458\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.3458\angle 56.3°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3458\angle 56.3°\ \Omega \times 25$$

$$Z_{sec} = 8.6462\angle 56.3°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.6462\angle 56.3°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.5185\angle 56.3°\ \Omega$$

Example Calculations: Options 1b and 7b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.5185\Omega}{\cos(85.0^{\circ} - 56.3°)}$$

$$Z_{max} < \frac{7.5185\ \Omega}{0.8771}$$

$$Z_{max} < \ 8.5715\angle 85.0°\ \Omega$$

Example Calculations: Option 1c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (24) $$P = \ GEN_{namplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (25) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (26) $$V_{gen} = 0.95\ p.u.\ \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Option 2a

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (27) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary current (I_{pri}):

Eq. (28) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 38389.9\ A$$

Secondary current (I_{sec}):

Eq. (29) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{38389.9\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.678\ \text{A}$$

To satisfy the 115% margin in Option 2a:

Eq. (30) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.678\ \text{A} \times 1.15$$

$$I_{\text{sec}\,limit} > 8.83\ \text{A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (31) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

Example Calculations: Option 2b

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (32) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

Eq. (33) $$P_{pu} = \frac{P}{MVA_{base}}$$

$$P_{pu} = \frac{767.6\ MW}{767.6\ MVA}$$

$$P_{pu} = 1.0\ p.u.$$

Reactive Power output (Q):

Eq. (34) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (35) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low\text{-}side}$ converges:

Eq. (36) $$\theta_{low-side} = \frac{\sin^{-1}\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}$$

Example Calculations: Option 2b

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

$$\theta_{low-side} = 7.3°$$

Eq. (37)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.9981 per unit for the second iteration:

Eq. (38)

$$\theta_{low-side} = \frac{\sin^{-1}\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8484}$$

$$\theta_{low-side} = 7.0°$$

Eq. (39)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987\ p.u.$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (40) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9987\ p.u.\ \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.88\ kV$$

Apparent power (S):

Eq. (41) $S = P_{reported} + jQ$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ \text{MVA}$$

Primary current (I_{pri}):

Eq. (42) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 21.88\ kV}$$

$$I_{pri} = 36519.8\ A$$

Secondary current (I_{sec}):

Eq. (43) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{36519.8\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.304\ \text{A}$$

To satisfy the 115% margin in Option 2b:

Eq. (44) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\text{sec}\,limit} > 7.304\ \text{A} \times 1.15$$

$$I_{\text{sec}\,limit} > 8.4\ \text{A}$$

Example Calculations: Option 2c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

Eq. (45) $P = GEN_{namplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (46) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (47) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$V_{gen} = 21.9\ kV$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (48) $V_{setting} < V_{gen} \times 75\%$

$V_{setting} < 21.9\ kV \times 0.75$

$V_{setting} < 16.429\ kV$

Example Calculations: Options 4, 10, and 17

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. Similarly, these calculations may also be applied to other asynchronous applications, including Option 17 for generator step-up transformers and lines that radially connect a generating plant to the Transmission system. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

Eq. (49) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (50) $$Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100\ Mvar \times 475.7\ Mva$$

$$Q = 575.7\ Mvar$$

Options 4, 10, and 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (51) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (52) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

$$\theta_{transient\ load\ angle} = 36.9°$$

Primary impedance (Z_{pri}):

Eq. (53) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{959.5\angle -36.9°\ MVA}$$

$$Z_{pri} = 0.5001\angle 36.9°\ \Omega$$

Example Calculations: Options 4, 10, and 17

Secondary impedance (Z_{sec}):

Eq. (54) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.5001\angle 36.9\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.5001\angle 36.9°\ \Omega \times 25$$

$$Z_{sec} = 12.502\angle 36.9°\ \Omega$$

To satisfy the 130% margin in Option 1a:

Eq. (55) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{12.502\angle 36.9°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 9.617\angle 36.9°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (56) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.617\ \ \Omega}{\cos(85.0° - 36.9°)}$$

$$Z_{max} < \frac{9.617\ \ \Omega}{0.6678}$$

$$Z_{max} < \ 14.401\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage restrained relay. In this application it was assumed 100Mvar of static compensation was added. Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

Eq. (57) $$P = \ GEN_{namplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

Example Calculations: Option 5

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (58) $$Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (59) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (60) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9^{\circ}\ MVA$$

Primary current (I_{pri}):

Eq. (61) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 25295.3\ A$$

Secondary current (I_{sec}):

Eq. (62) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{25295.3\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.06\ \text{A}$$

Example Calculations: Option 5

To satisfy the 130% margin in Option 5:

Eq. (63) $I_{\sec limit} > I_{sec} \times 130\%$

$I_{\sec limit} > 5.06 \text{ A} \times 1.30$

$I_{\sec limit} > 6.58\angle - 36.9° \, A$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

Option 8a represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to a synchronous generator. Similarly, these calculations can be applied to other synchronous generator applications, including Option 9a for generator step-up transformers applying a phase directional time overcurrent (67) directional toward the Transmission system relay, and Option 15a and 16a for lines that radially connect a generating plant to the Transmission system using a phase time overcurrent (51) and phase directional time overcurrent (67) directional toward the Transmission system relay, respectively. Options 8b and 9b use the same process, except the bus voltage is 0.85 per unit is used instead of 0.95 and excludes the generator step-up (GSU) impedance.

This example uses Option 8b as an example.

Real Power output (P):

Eq. (64) $P = \; GEN_{namplate} \times pf$

$P = 903 \; MVA \; \times 0.85$

$P = 767.6 \; MW$

Reactive Power output (Q):

Eq. (65) $Q = 150\% \times P$

$Q = 1.5 \times 767.6 \; MW$

$Q = 1151.3 \; Mvar$

Option 8b, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (66) $V_{bus} = 0.85 \; p.u. \; \times V_{nom}$

$V_{gen} = 0.85 \times 345 \; kV$

$V_{gen} = 293.25 \; kV$

Apparent power (S):

Eq. (67) $S = P_{reported} + jQ$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2724.3\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{2724.3\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 0.545\ \mathrm{A}$$

To satisfy the 115% margin in Option 8a:

Eq. (70) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 0.545\ \mathrm{A} \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 0.627\ \mathrm{A}$$

Example Calculations: Options 7c, 8c, 9c 14b, 15b, and 16b

These options require simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 11a and 12

Option 11 represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

Eq. (71) $P = GEN_{namplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (72) $Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $S = P_{reported} + jQ$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 25295\ A$$

Example Calculations: Options 11a and 12

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{25295\text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.059\text{ A}$$

To satisfy the 130% margin in Options 11 and12:

Eq. (77) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 5.059\text{ A} \times 1.30$$

$$I_{\sec limit} > 6.575\text{ A}$$

Example Calculations: Option 13a and 13b

Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

Primary current (I_{pri}):

Eq. (78) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (79) $$I_{sec} = \frac{I_{pri}}{CT_{uat}}$$

$$I_{sec} = \frac{2510.2\text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

Example Calculations: Option 13a and 13b

To satisfy the 150% margin in Option 13a:

Eq. (80) $I_{\sec limit} > I_{sec} \times 150\%$

$I_{\sec limit} > 2.51 \text{ A} \times 1.50$

$I_{\sec limit} > 3.77 \text{ A}$

Example Calculations: Option 14a

Option 14a represents the calculation for lines that radially connect an asynchronous generating plant to the Transmission system for a phase directional time overcurrent (67) directional toward the Transmission system relay.

Real Power output (P):

Eq. (81) $P = \; GEN_{namplate} \times pf$

$P = 903 \; MVA \; \times 0.85$

$P = 767.6 \; MW$

Reactive Power output (Q):

Eq. (82) $Q = 150\% \times P$

$Q = 1.5 \times 767.6 \; MW$

$Q = 1151.3 \; Mvar$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the generator step-up (GSU) voltage (V_{nom}):

Eq. (83) $V_{bus} = 0.85 \; p.u. \; \times V_{nom}$

$V_{gen} = 0.85 \times 345 \; kV$

$V_{gen} = 293.25 \; kV$

Apparent power (S):

Eq. (84) $S = P_{reported} + jQ$

$S = 767.6 \; MW + j1151.3 \; Mvar$

$S = 1383.7\angle 56.3° \; MVA$

$\theta_{transient \; load \; angle} = 56.3°$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 62.1481\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 62.1481\angle 56.3°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 62.1481\angle 56.3°\ \Omega \times 25$$

$$Z_{sec} = 1553.7\angle 56.3°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{1553.7\angle 56.3°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 1351.0\angle 56.3°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{1351.0\ \Omega}{\cos(85.0° - 56.3°)}$$

$$Z_{max} < \frac{1651.0\ \Omega}{0.8771}$$

$$Z_{max} < 1540.3\angle 85.0°\ \Omega$$

Example Calculations: Options 11b, 18, and 19

Option 11b represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 18 may also be applied here as well for generation interconnection Facilities and Option 19 for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 100 Mvar of static compensation was added.

Real Power output (P):

Eq. (89) $P = GEN_{namplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (90) $Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Options 11b, 18, and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (91) $V_{nom} = 1.0\ p.u.\ \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345\ kV$$

Apparent power (S):

Eq. (92) $S = P_{reported} + jQ$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 1605\ A$$

Example Calculations: Options 11b, 18, and 19

Secondary current (I_{sec}):

Eq. (94) $$I_{sec} = \frac{I_{pri}}{CT_{HV}}$$

$$I_{sec} = \frac{1605\text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 4.014\text{ A}$$

To satisfy the 130% margin in Options 11b, 18, and 19:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 4.014\text{ A} \times 1.30$$

$$I_{\sec limit} > 5.218\text{ A}$$

End of calculations

Guidelines and Technical Basis

Introduction

The document, “Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The term, “while maintaining reliable fault protection” in Requirement R1, describes that the Generator Owner (“responsible entity~~ (“Generator Owner~~”) is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generation unit or plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the responsible entity consider both the requirement~~s~~ within this standard and its desired protection goals, and perform modifications to its protecti~~on~~ve relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be necessary to replace the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the responsible entity must understand the ~~criteria and application~~applications of Table 1, Relay Loadability Evaluation Criteria (“Table 1~~”),~~”) in determining the settings that it must ~~install on~~apply to each of its load-responsive protective relays to ~~achieve the required~~prevent an unnecessary trip of its generator ~~performance~~ during the ~~transient~~system conditions anticipated by this standard.

Applicability

The drafting team recognizes that some Generator Owners own an interconnection facility (in some cases labeled a “transmission Facility” or “generator leads”) between the generator and the interface with the portion of the BES where Transmission Owners take over the ownership. In these cases, the Generator Owners own sole-use Facilities that are connected to the boundary of the interconnected system. Load-responsive protective relays applied by the Generator Owner at the terminals of these Facilities to protect these interconnection Facilities are included in the scope of this standard.

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and ~~the resultant increase in apparent power~~ may result in operation of generation system load-responsive ~~generator~~ protective ~~functions,~~relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter ~~may~~will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing ~~and~~given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator ~~backup protection, it is important to evaluate~~ load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition ~~during which the generator is not at risk of thermal damage~~.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1~~,~~ are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other~~,~~ undesired~~,~~ behavior occurred.

The dynamic load levels specified in Table 1 under column ~~Pick Up~~"Pickup Setting ~~c~~Criteria~~,~~," are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the generator step-up transformer. These values are based on ~~values recorded during~~records from the events leading to the August 14, 2003 blackout, other subsequent ~~s~~System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified ~~load operating points are believed to~~criteria represent conservative~~,~~ but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20~~%~~ percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options ~~1~~1a (0.95 per unit) and ~~2,~~1b (0.85 per unit), for example, are based on relatively simple, but conservative calculations~~.~~ of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output~~,~~ Option ~~3, for example,~~1c (simulation) was developed to allow ~~an~~the responsible entity to simulate the output of a generating unit when the simple calculation is ~~too conservative~~not adequate to achieve the desired protective ~~function~~relay setting.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a ~~D~~disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. ~~They~~These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (i.e~~.g., Option~~., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19), for ~~induction~~asynchronous generator installations.

Synchronous Generator Simulation Criteria

The responsible entity who elects to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in megawatts as reported to the Planning Coordinator or Transmission Planner.

Phase Distance Relay ~~(Options 1-4~~ – Directional Toward Transmission System (21))

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. ~~The Options 1 through 4~~ These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

~~Phase distance protection~~The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. ~~When phase distance protection is applied, its function is to provide backup protection for system faults that have not been cleared by Transmission system circuit breakers via their protective relays.~~

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***~~which~~that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition ~~which~~that causes the generator voltage regulator to boost generator excitation for a sustained period ~~that~~ may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor ~~(sic: This setting can be re-stated in terms of ohms as 0.66 – 0.50 per unit ohms on the machine base.)~~ has been shown to provide good coordination for stable swings, system faults involving ~~infeed~~in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine ~~-~~generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment ~~blinders~~binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be*

> *set as previously described~~ above~~. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the ~~generator step-up~~GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. ~~Your~~The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso~~lated~~-phase bus with partial coverage of the ~~generator step-up~~GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

~~Table 1, Options 1, 2, and 3, are provided for assessing loadability for synchronous generators. The generator-side voltage during field forcing will be higher than the high-side voltage due to the voltage drop resulting from the Reactive Power flow through the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~

~~Option 1 accounts for the voltage drop across the generator step-up transformer using a conservative estimate of the generator-side voltage. This is based on referring a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer through the turns ratio.~~

~~Option 2 uses a calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This option accounts for the voltage drop through the generator step-up transformer, including the turns-ratio and impedance.~~

~~Option 3 uses a simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The responsible entity must perform simulations to determine the actual performance of its generator. The responsible entity that elects to determine the synchronous generator performance on which to base phase distance relay settings may simulate the response of a generator to depressed Transmission system by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling switching of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator holding the assigned voltage schedule while at 100% of the maximum seasonal gross Real Power capability value as reported to the Planning Coordinator.~~

~~Option 4 is based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Since asynchronous generators~~

~~do not produce as much reactive power as synchronous generators, the voltage rise due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high side nominal voltage to the generator side based on the generator step-up transformer's turns ratio. The aggregate megavoltampere (MVA) output is determined by summing the total nameplate MW and megavoltampere-reactive (Mvar) capability of the generation equipment behind the relay. This should also include any static or dynamic reactive power devices that contribute to the power flow through the relay.~~

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability ~~(i.e., field forcing).~~ .

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may restrict the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. The examples in Appendix E ~~"~~of the Power Plant and Transmission System Protection Coordination~~," published by the NERC System Protection and Control Subcommittee,~~ technical reference document illustrate the potential for encroaching on the generating unit capability.

~~If an entity is unable to meet the criteria established within Table 1, while maintaining reliable protection, the entity will need to utilize different protective relays or protection philosophies such that both goals can be met.~~

~~Generator Phase~~

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (~~Options 5-8~~51V-R)

~~Generator~~ Phase time overcurrent voltage-restrained ~~phase overcurrent~~ relays~~,~~ (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by ~~Voltage Restrained~~voltage-restrained and ~~Voltage Controlled~~voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

~~Table 1, Options 5 through 8, establish criteria for phase~~

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays ~~which change their sensitivity~~(51V-C), enabled as a function of voltage~~ to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices~~, are variably referred to by IEEE function numbers ~~(~~51V~~), (51R), (51VR), (~~, 51C, 51VC, 51V/~~R), (~~C, 51V-~~R),~~C, or other terms. ~~The criteria provided for these relays are very similar to those provided for phase distance relays in Options 1 through 4.~~ See ~~clause~~section 3.10 of ~~"~~the Power Plant and Transmission System Protection Coordination~~," published by the NERC System Protection and Control Subcommittee (SPCS)~~ technical reference document for a detailed discussion of this protection function.

~~Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.~~

~~Generator~~ Phase Directional Time Overcurrent ~~Relays – Voltage Controlled (Option 9~~Relay – Directional Toward Transmission System (67)

~~Generator voltage-controlled overcurrent relays, enabled as a function of voltage, are applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together, and many other generators were tripped by unknown protection functions.~~

~~Table 1, Option 9, establishes criterion for phase overcurrent relays which are enabled as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51C), (51VC), (51V/C), (51V-C), or other terms.~~ See ~~clause~~section 3.~~10~~9.2 of ~~"~~the Power Plant and Transmission System Protection Coordination~~," published by the NERC System Protection and Control Subcommittee~~ technical reference document for a detailed discussion of ~~this~~the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays are similar. Note that the setting criteria ~~for a voltage-control setting of less~~established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than ~~0.75~~

~~per unit of the nominal~~establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator ~~voltage is~~ output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in these options are based on guidance found in ~~“~~the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. ~~,” published by the NERC SPCS.~~ This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer

(excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage ~~is~~are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

~~Refer to the discussion under~~

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4 ~~technical basis concerning~~)

Table 1, Option 4 is provided for assessing loadability for asynchronous ~~and inverter~~generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer ~~Phase Time Overcurrent Relay (Options 10-12~~(Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 7a, 7b, and 7c))

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. ~~Table 1, Options 10 through 12, establish criteria for the generator protective~~

~~relays to prevent the generator step-up transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard~~These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

~~The stressed system conditions, anticipated by Options 10 through 12, reflect a 0.85 per unit Transmission system voltage; therefore, establishes that the ampere value used for applying the generator step-up transformer phase time overcurrent relay be calculated from the apparent power addressed within the~~ Table 1, ~~with application of a 0.85 per unit Transmission system voltage.~~

Options ~~10~~7a, 7b, and ~~11 apply to~~7c, are provided for assessing loadability for generator step-up transformers ~~connected to~~ applying phase distance relays that are directional toward the Transmission system on synchronous generators~~. Option 12 only applies to generator step-up transformers connected to asynchronous generators (including inverter-based installations).~~ that are connected to the generator-side of the generator step-up transformer of a synchronous generator.

~~Please see clause~~Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers.

Note that the setting criteria established within these options differ from section 3.9.2 of ~~"~~the Power Plant and Transmission System Protection Coordination~~," published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function. However, the setting criteria established within Options 10-12 differ from that suggested in this paper.~~ technical reference document. Rather than establishing a uniform setting threshold of 200~~%~~ percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side or high-side of the generator step-up transformer of a synchronous generator.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on ~~whether the generator operates synchronous or asynchronous~~a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

~~Refer to the discussion under~~ Option ~~4 technical basis concerning asynchronous~~8c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and ~~inverter based~~8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Distance~~Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options ~~13, 14, 15,~~9a, 9b and ~~16~~9c)

~~The~~ The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph ~~112~~104, directs that NERC address relay loadability for protective relays applied ~~for system backup protection. In paragraph 114, FERC further explains that their concern applies whether~~on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Options 11a and 11b)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11a, address those ~~relays are~~ generator step-up transformer phase time overcurrent relays installed on the low-side (i.e., generator~~ terminals or on the generator -~~-side) of the generator step-up transformer~~. Their concerns regarding~~ of an asynchronous generator, and Option 11b addresses those relays ~~connected to~~installed on the high-side (i.e., line-side) of the generator ~~terminals are addressed in Options 1, 2, 3, and 4 for the generator itself; Table 1, Options 13, 14, 15, and 16, for generator~~ step-up transformer ~~distance relays address those connected to the generator side of the generator step-up transformer~~of an asynchronous generator.

~~The generator protective relays in Options 13, 14, 15, and 16 prevent generator step-up transformer phase distance relays from operating during the dynamic conditions anticipated by this standard.~~

Option 11a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer for overcurrent relays installed on the low-side. The voltage drop across the generator step-up transformer is calculated based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio of the generator step-up transformer. This is a simple calculation that approximates the stressed system conditions.

Where the relay current is supplied from the generator bus, Option 11a, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio. Where the relay current is supplied from the high-side of the transformer, it is necessary to assess loadability using the high-side nominal voltage in Option 11b.

For Options 11a and 11b, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer

(excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Option ~~17)~~13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) ("UAT")that supply normal station service for a generating unit. ~~The~~ For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, ~~Option 17,~~Options 13a and 13b provide two options for ~~auxiliary transformers addresses~~addressing phase time overcurrent relay~~s~~ing protecting ~~auxiliary transformers that are used to provide overall auxiliary power to the generating station when~~UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator ~~is running (regardless of where these transformers~~isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relaying applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are ~~connected). This discussion refers to each~~not a part of ~~these transformers as a "unit auxiliary transformer" or "UAT." If the UAT trips, it will result in tripping of the generator itself, either directly or indirectly.~~ this standard. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating unit or plant.

Refer to the figures below for example configurations:

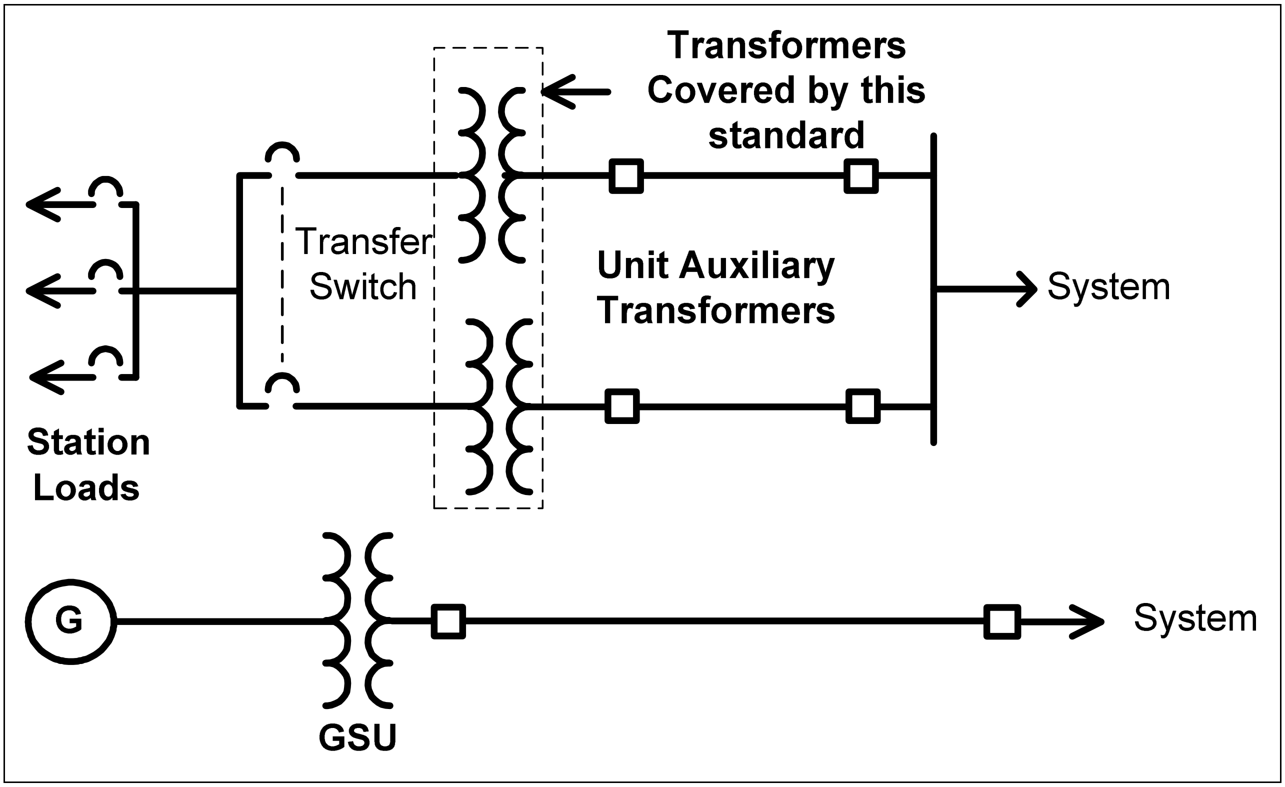

Figure-1 – Auxiliary Power System (~~I~~independent from ~~G~~generator)

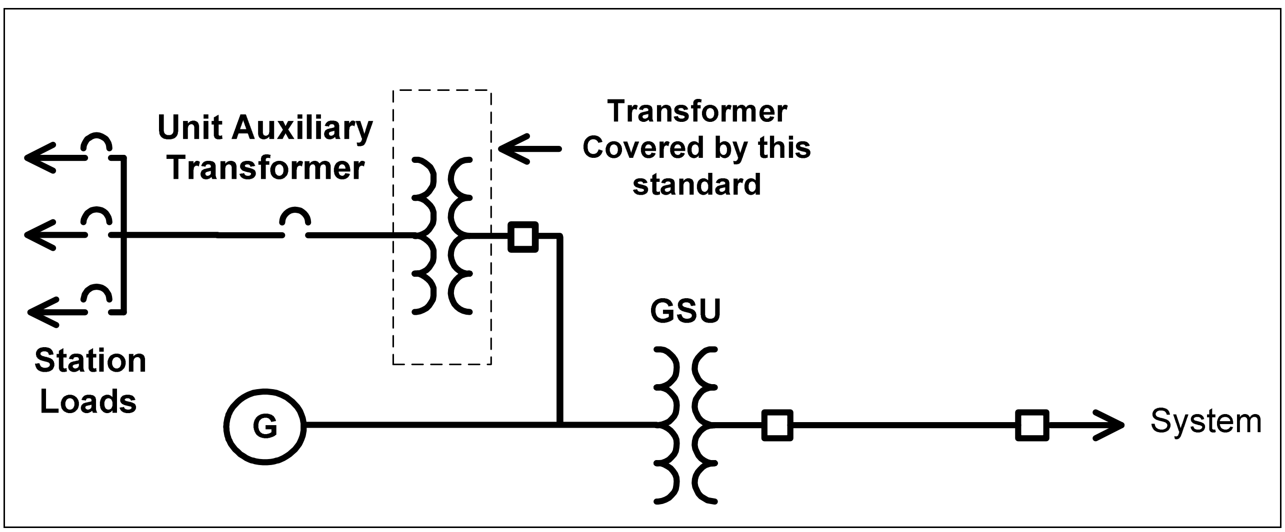

Figure-2 – Typical ~~Auxiliary Power System~~auxiliary power system for ~~Power Plants~~generation units or plants.

The UATs supplying power to the ~~plant's~~unit or plant electrical auxiliaries are sized to accommodate ~~for~~ the maximum expected ~~auxiliary~~UAT load demand at the highest generator output. Although the MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

The performance of the ~~auxiliary~~UAT loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of ~~auxiliary~~UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150~~%~~ percent from that used elsewhere in this standard (~~i.~~e.g., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150~~%~~ percent of maximum nameplate MVA rating at 1.0 per unit generator bus voltage ~~would~~will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased ~~auxiliary~~UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 14a and 14b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator step-up transformer phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Option 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 15a and 15b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 16a and 16b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Generator nameplate (MVA @ rated pf):	$GEN_{nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen} = 22\ kV$
Real Power output in MW as reported to the PC or TP:	$P_{reported} = 767.6\ MW$
Generator step-up transformer impedance (903 MVA base):	$Z_{gsu} = 12.14\%$
Generator step-up transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer ratio:	$PT_{ratio} = \frac{200}{1}$
Auxiliary transformer nameplate:	$UAT_{nameplate} = 60\ MVA$
Auxiliary low-side voltage:	$V_{uat} = 13.8\ kV$
Auxiliary current transformer:	$CT_{uat} = \frac{5000}{5}$
Transformer High Voltage CT:	$CT_{HV} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 100\ Mvar$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 0.3130\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.3130\angle 56.3°\,\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3130\angle 56.3°\,\Omega \times 25$$

$$Z_{sec} = 7.8238\angle 56.3°\,\Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{7.8238\angle 56.3°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 6.8033\angle 56.3°\,\Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.8033\,\Omega}{\cos(85.0° - 56.3°)}$$

$$Z_{max} < \frac{6.8033\,\Omega}{0.8771}$$

$$Z_{max} < 7.7561\angle 85.0°\,\Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance (21) directional toward the Transmission system relay. This option requires calculating low-side voltage taking into account voltage drop across the generator step-up transformer. Similarly these calculations may be applied to Option 7b for generator step-up transformers applying a phase distance (21) directional toward the Transmission system relay.

Real Power output (P):

Eq. (9) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P}{MVA_{base}}$

$$P_{pu} = \frac{767.6\ MW}{767.6\ MVA}$$

$$P_{pu} = 1.0\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low\text{-}side}$ converges:

Eq. (14) $\theta_{low-side} = \frac{\sin^{-1}\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

$$\theta_{low-side} = 7.3°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9981 per unit for the second iteration:

Eq. (16)

$$\theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8484}$$

$$\theta_{low-side} = 7.0°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987\ p.u.$$

Example Calculations: Options 1b and 7b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9987\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.88\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°$$

Primary Impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.88\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 0.3458\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.3458\angle 56.3°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3458\angle 56.3°\ \Omega \times 25$$

$$Z_{sec} = 8.6462\angle 56.3°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.6462\angle 56.3°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.5185\angle 56.3°\ \Omega$$

Example Calculations: Options 1b and 7b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.5185\Omega}{\cos(85.0^{\circ} - 56.3^{\circ})}$$

$$Z_{max} < \frac{7.5185\ \Omega}{0.8771}$$

$$Z_{max} < 8.5715\angle 85.0^{\circ}\ \Omega$$

Example Calculations: Option 1c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (24) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (25) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (26) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Option 2a

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (27) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary current (I_{pri}):

Eq. (28) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 38389.9\ A$$

Secondary current (I_{sec}):

Eq. (29) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{38389.9\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.678\ \mathrm{A}$$

To satisfy the 115% margin in Option 2a:

Eq. (30) $$I_{\mathrm{sec}\ limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\ limit} > 7.678\ \mathrm{A} \times 1.15$$

$$I_{\mathrm{sec}\ limit} > 8.83\ \mathrm{A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (31) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

Example Calculations: Option 2b

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (32) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

Eq. (33) $$P_{pu} = \frac{P}{MVA_{base}}$$

$$P_{pu} = \frac{767.6\ MW}{767.6\ MVA}$$

$$P_{pu} = 1.0\ p.u.$$

Reactive Power output (Q):

Eq. (34) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (35) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low\text{-}side}$ converges:

Eq. (36) $$\theta_{low-side} = \frac{\sin^{-1}\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}$$

Example Calculations: Option 2b

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

$$\theta_{low-side} = 7.3°$$

Eq. (37)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.9981 per unit for the second iteration:

Eq. (38)
$$\theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8484}$$

$$\theta_{low-side} = 7.0°$$

Eq. (39)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987\ p.u.$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (40) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9987\ p.u. \ \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.88\ kV$$

Apparent power (S):

Eq. (41) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ \text{MVA}$$

Primary current (I_{pri}):

Eq. (42) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 21.88\ kV}$$

$$I_{pri} = 36519.8\ A$$

Secondary current (I_{sec}):

Eq. (43) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{36519.8\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.304\ \text{A}$$

To satisfy the 115% margin in Option 2b:

Eq. (44) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.304\ \text{A} \times 1.15$$

$$I_{\sec limit} > 8.4\ \text{A}$$

Example Calculations: Option 2c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

Eq. (45) $P = GEN_{namplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (46) $Q = 150\% \times P$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (47) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (48) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Options 4, 10, and 17

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. Similarly, these calculations may also be applied to other asynchronous applications, including Option 17 for generator step-up transformers and lines that radially connect a generating plant to the Transmission system. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

Eq. (49) $P = GEN_{namplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (50) $Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 100\ Mvar \times 475.7\ Mva$$

$$Q = 575.7\ Mvar$$

Options 4, 10, and 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (51) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (52) $S = P_{reported} + jQ$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

$$\theta_{transient\ load\ angle} = 36.9°$$

Primary impedance (Z_{pri}):

Eq. (53) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{959.5\angle -36.9°\ MVA}$$

$$Z_{pri} = 0.5001\angle 36.9°\ \Omega$$

Example Calculations: Options 4, 10, and 17

Secondary impedance (Z_{sec}):

Eq. (54) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.5001\angle 36.9\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.5001\angle 36.9°\ \Omega \times 25$$

$$Z_{sec} = 12.502\angle 36.9°\ \Omega$$

To satisfy the 130% margin in Option 1a:

Eq. (55) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{12.502\angle 36.9°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 9.617\angle 36.9°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (56) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.617\ \ \Omega}{\cos(85.0° - 36.9°)}$$

$$Z_{max} < \frac{9.617\ \ \Omega}{0.6678}$$

$$Z_{max} < \ 14.401\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage restrained relay. In this application it was assumed 100Mvar of static compensation was added. Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

Eq. (57) $$P = \ GEN_{namplate} \times pf$$

$$P = 903\ MVA\ \ \times 0.85$$

Example Calculations: Option 5

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (58) $$Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (59) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (60) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

Primary current (I_{pri}):

Eq. (61) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 25295.3\ A$$

Secondary current (I_{sec}):

Eq. (62) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{25295.3\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.06\ \text{A}$$

Example Calculations: Option 5

To satisfy the 130% margin in Option 5:

Eq. (63) $I_{\sec limit} > I_{sec} \times 130\%$

$I_{\sec limit} > 5.06\ \mathrm{A} \times 1.30$

$I_{\sec limit} > 6.58\angle -36.9°\ A$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

Option 8a represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to a synchronous generator. Similarly, these calculations can be applied to other synchronous generator applications, including Option 9a for generator step-up transformers applying a phase directional time overcurrent (67) directional toward the Transmission system relay, and Option 15a and 16a for lines that radially connect a generating plant to the Transmission system using a phase time overcurrent (51) and phase directional time overcurrent (67) directional toward the Transmission system relay, respectively. Options 8b and 9b use the same process, except the bus voltage is 0.85 per unit is used instead of 0.95 and excludes the generator step-up (GSU) impedance.

This example uses Option 8b as an example.

Real Power output (P):

Eq. (64) $P = GEN_{namplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (65) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 8b, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (66) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$V_{gen} = 0.85 \times 345\ kV$

$V_{gen} = 293.25\ kV$

Apparent power (S):

Eq. (67) $S = P_{reported} + jQ$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

$$S = 767.6\ MW + j1151.3\ Mvar$$

$$S = 1383.7\angle 56.3°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1383.7\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2724.3\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{2724.3\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 0.545\ \mathrm{A}$$

To satisfy the 115% margin in Option 8a:

Eq. (70) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 0.545\ \mathrm{A} \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 0.627\ \mathrm{A}$$

Example Calculations: Options 7c, 8c, 9c 14b, 15b, and 16b

These options require simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 11a and 12

Option 11 represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

Eq. (71) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u.\ \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 25295\ A$$

Example Calculations: Options 11a and 12

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{25295\text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.059\text{ A}$$

To satisfy the 130% margin in Options 11 and12:

Eq. (77) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 5.059\text{ A} \times 1.30$$

$$I_{\sec limit} > 6.575\text{ A}$$

Example Calculations: Option 13a and 13b

Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

Primary current (I_{pri}):

Eq. (78) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (79) $$I_{sec} = \frac{I_{pri}}{CT_{uat}}$$

$$I_{sec} = \frac{2510.2\text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

Example Calculations: Option 13a and 13b

To satisfy the 150% margin in Option 13a:

Eq. (80) $I_{\sec limit} > I_{sec} \times 150\%$

$I_{\sec limit} > 2.51 \text{ A} \times 1.50$

$I_{\sec limit} > 3.77 \text{ A}$

Example Calculations: Option 14a

Option 14a represents the calculation for lines that radially connect an asynchronous generating plant to the Transmission system for a phase directional time overcurrent (67) directional toward the Transmission system relay.

Real Power output (P):

Eq. (81) $P = GEN_{namplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (82) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the generator step-up (GSU) voltage (V_{nom}):

Eq. (83) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$V_{gen} = 0.85 \times 345\ kV$

$V_{gen} = 293.25\ kV$

Apparent power (S):

Eq. (84) $S = P_{reported} + jQ$

$S = 767.6\ MW + j1151.3\ Mvar$

$S = 1383.7\angle 56.3°\ MVA$

$\theta_{transient\ load\ angle} = 56.3°$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1383.7\angle -56.3°\ MVA}$$

$$Z_{pri} = 62.1481\angle 56.3°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 62.1481\angle 56.3°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 62.1481\angle 56.3°\ \Omega \times 25$$

$$Z_{sec} = 1553.7\angle 56.3°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{1553.7\angle 56.3°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 1351.0\angle 56.3°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{1351.0\ \Omega}{\cos(85.0° - 56.3°)}$$

$$Z_{max} < \frac{1651.0\ \Omega}{0.8771}$$

$$Z_{max} < 1540.3\angle 85.0°\ \Omega$$

Example Calculations: Options 11b, 18, and 19

Option 11b represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 18 may also be applied here as well for generation interconnection Facilities and Option 19 for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 100 Mvar of static compensation was added.

Real Power output (P):

Eq. (89) $$P = GEN_{namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (90) $$Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100\ Mvar + 475.7\ Mvar$$

$$Q = 575.7\ Mvar$$

Options 11b, 18, and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (91) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345\ kV$$

Apparent power (S):

Eq. (92) $$S = P_{reported} + jQ$$

$$S = 767.6\ MW + j575.7\ Mvar$$

$$S = 959.5\angle 36.9°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 1605\ A$$

Example Calculations: Options 11b, 18, and 19

Secondary current (I_{sec}):

Eq. (94) $$I_{sec} = \frac{I_{pri}}{CT_{HV}}$$

$$I_{sec} = \frac{1605\text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 4.014\text{ A}$$

To satisfy the 130% margin in Options 11b, 18, and 19:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 4.014\text{ A} \times 1.30$$

$$I_{\sec limit} > 5.218\text{ A}$$

End of calculations

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Relay Loadability: Generator.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on "pass-fail" or a binary condition. The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Project 2010-13.2 Generator Relay Loadability

Consideration of Issues and Directives

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
NERC Ref: S-10724 Para 106 supported by Paragraphs 104, 105, and 108. **106.** We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability. Para 104, 105, and 108 **104.** We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC-023-1 to address	Order No. 733 (Para 104, 105, 106, and 108)	**Response to P106** The Reliability Standard PRC-025-1 is responsive to paragraph 106 by establishing a new standard that addresses generator unit relay loadability for load-responsive protective relays applicable to generators for the conditions (depressed voltages) observed during the August 2003 blackout in the northeastern portion of North America. **Response to P104** The Reliability Standard PRC-025-1 is responsive to paragraph 104 by establishing requirements for load-responsive protective relays on generator step-up (GSU) transformers and on unit auxiliary transformers (UAT) that supply station service power to support the on-line

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC-023-1. **105.** In light of the EROs statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a		operation of generating plants. These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. The standard is coordinated with the expected outcomes of PRC-023-2 in that it will assure that the applicable equipment will not be removed from service unnecessarily for the conditions observed during the August 2003 blackout in the northeastern portion of North America. **Response to P105** The Reliability Standard PRC-025-1 is responsive to paragraph 105 by developing a new standard to address generator relay loadability according to the filed schedule. This Phase II of relay loadability required an extension of time to complete, extending the deadline to September 30, 2013. A one year extension was granted on February 15, 2012, Docket No. RM08-13-001. **Response to P108** The Reliability Standard PRC-025-1 is responsive to

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA. **108.** Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.		paragraph 108 by establishing a requirement for each Generator Owner to apply settings on its load-responsive protective relays for generator step-up transformers (including, generator units and unit auxiliary transformers). For generator step-up (GSU) transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on a percentage of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to the Planning Coordinator and Transmission Planner; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar). For generator step-up (GSU) transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on a percentage of the generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the connected generators at rated power factor. Asynchronous generator criteria also include inverter-based

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		installations. Unit auxiliary transformers unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating plants are based on a percentage of the MVA rating of the transformers or the auxiliary loads at the rated MW as reported to the Planning Coordinator or Transmission Planner. These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013
Formal Comment Period: January 25 – March 11, 2013

Additional Documents Posted for Comment:
Cost Effectiveness Comment Period: January 25 – March 11, 2013
Supplemental SAR Informal Comment Period: January 25 – March 11, 2013
RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:
Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

Now Available

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

In response to concerns expressed by stakeholders and regulators, NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. The revisions under Project 2010-13.2 have been deemed to be required to meet an adequate level of reliability, and therefore, “Phase I” of the CEAP (a cost impact assessment) is unnecessary. A pilot of “Phase II” of the CEAP, the CEA, is posted for industry comment through **8 p.m. Eastern on Monday, March 11, 2013**. More information about the CEAP is available on the project page.

A supplemental SAR has also been developed to revise PRC-023-2 and is posted for an informal comment period.

Finally, PRC-025-1 was drafted in conjunction with the development of its RSAW, which is posted for an informal comment period.

Instructions for Joining Ballot Pool(s)

Ballots pools are being formed for the standard and non-binding poll for PRC-025-1. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-025-1 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool.

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list servers for the ballot pools are:

Initial ballot: bp-2010-13.2_PRC-025-1_in@nerc.com
Non-binding poll: bp-2010-13.2_NB_PRC-025_in@nerc.com

Instructions for Commenting

A formal comment period is open for PRC-025-1 through **8 p.m. Eastern on Monday, March 11, 2013**. The supplemental SAR to revise PRC-023-2 and CEA have also been posted for industry comment. Please use the links below to the electronic comment forms to submit comments:

PRC-025-1
Supplemental SAR
Cost Effective Analysis

If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

A comment period on the draft RSAW is open through **8 p.m. Eastern on Monday, March 11, 2013**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the project page and sending to: RSAWfeedback@nerc.net.

Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

The March 18, 2010 FERC Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
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Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013
Formal Comment Period: January 25 – March 11, 2013

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RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:
Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

Now Available

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

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PRC-025-1
Supplemental SAR
Cost Effective Analysis

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Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

The March 18, 2010 FERC Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the project page.

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North American Electric Reliability Corporation
3353 Peachtree Rd, NE
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation PRC-025-1

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot of **PRC-025-1** concluded at **8 p.m. Eastern on Monday, March 11, 2013** and the non-binding poll of the associated VRFs and VSLs concluded at **8 p.m. Eastern on Tuesday, March 12, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the initial ballot.

Approval	Non-binding Poll Results
Quorum: 76.36% Approval: 54.65%	Quorum: 84.26% Supportive Opinions: 51.88%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process

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For more information or assistance, please contact Monica Benson, Reliability Standards Analyst, at monica.benson@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Initial Ballot Jan 2013_in
Ballot Period:	3/1/2013 - 3/11/2013
Ballot Type:	Initial
Total # Votes:	281
Total Ballot Pool:	368
Quorum:	**76.36 % The Quorum has been reached**
Weighted Segment Vote:	54.65 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	98	1	31	0.492	32	0.508	10	25
2 - Segment 2.	10	0.6	5	0.5	1	0.1	3	1
3 - Segment 3.	81	1	28	0.483	30	0.517	6	17
4 - Segment 4.	28	1	9	0.5	9	0.5	2	8
5 - Segment 5.	80	1	20	0.37	34	0.63	7	19
6 - Segment 6.	54	1	18	0.462	21	0.538	4	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.3	2	0.2	1	0.1	0	4
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1
10 - Segment 10.	7	0.5	4	0.4	1	0.1	1	1
Totals	**368**	**6.6**	**119**	**3.607**	**129**	**2.993**	**33**	**87**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	paul B johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer		
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery		

1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		

4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Michael Shultz	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Negative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Negative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart		
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin		
6	City of Colorado Springs	Shannon Fair	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Blair Mukanik	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Affirmative	

6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis	Abstain	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Non-binding Poll Results

Project 2010-13.2 Relay Loadability

Ballot Results	
Non-binding Poll Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Non-binding
Poll Period:	3/1/2013 - 3/12/2013
Total # Opinions:	289
Total Ballot Pool:	343
Summary Results:	84.26% of those who registered to participate provided an opinion or an abstention; 51.88% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	paul B johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Negative	

1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	

1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Negative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	

3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Affirmative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	

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3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky	Mike D Kukla	Affirmative	

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	peak power plant project			
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Michael Shultz	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Negative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Platte River Power Authority	Roland Thiel		

5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Western Farmers Electric Coop.	Clem Cassmeyer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Colorado Springs	Shannon Fair		
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	

6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Blair Mukanik	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Draft 3

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 2 of PRC-025-1, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and Initial Ballot	January 2013
30-day Formal Comment Period and Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities.

3.2. Facilities: The following Elements associated with Bulk Electric System generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

3.2.4 Generator interconnection Facility(ies).

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

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[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner to use any of the protective functions listed in Table 1. Each Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities shall use one of the following Options 1-19 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on a generator interconnection Facility, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in the table. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exceptions

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions),
- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard, or
- Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full-load current, and supervised to prevent operation below 115% of full-load current.
- Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase time overcurrent relay (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts below				
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51) that trips the generator either directly or via an interposing auxiliary/lockout relay	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO)
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase time overcurrent relay (51)	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 2 of PRC-025-1, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and~~with Parallel~~ Initial Ballot	January 2013~~2~~
30-day Formal Comment Period and~~with Parallel~~ Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

Purpose: To set load-responsive ~~generator~~ protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage~~damaging the generator~~.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities.

3.2. Facilities: The following Elements associated with Bulk Electric System generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

3.2.4 Generator interconnection Facility(ies).

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), ~~,~~ or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA)~~CEA~~ may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner to use any of the protective functions listed in Table 1. Each Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities shall use one of the following Options 1-19 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO),~~,~~ and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization,~~,~~ including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on a generator interconnection Facility, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized~~no-load~~ tap changers (DETC). If ~~NLTC). On~~ load tap changers (~~O~~LTC) are ~~rarely used for GSU transformers; when~~ used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall~~may~~ be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in the table. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exceptions

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions),
- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard, or
- Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full-load current, and supervised to prevent operation below 115% of full-load current.
- Protection systems that detect transformer overloads and~~Protection systems that~~ are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~(including the transformer turns ratio and impedance)~~	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Synchronous generators	Phase time overcurrent relay (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to ~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~(including the transformer turns ratio and impedance)~~	The overcurrent element shall be set greater than 115% o the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current, derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
Generator step-up transformer connected to~~–~~ synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~(including the transformer turns ratio and impedance)~~	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer connected to– synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~(including the transformer turns ratio and impedance)~~	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer connected to– synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the ~~connected~~ aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the ~~connected~~ aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~(including the transformer turns ratio and impedance)~~	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the ~~connected~~ aggregate generation maximum gross Mvar output determined by simulation
A different application starts on the next page				
Generator step-up transformer connected to– asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU If the relay is installed on the	11~~a~~	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current, derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		~~**OR**~~		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	high-side of the GSU use Option 18	~~11b~~	~~1.0 per unit of the high-side nominal voltage for overcurrent relays installed on the high-side~~	~~The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU If the relay is installed on the high-side of the GSU use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51) that trips the generator either directly or via an interposing auxiliary/lockout relay	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO)
A different application starts below				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Generator interconnection Facilities connected to~~–~~ synchronous generators	Phase distance relay (21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – ~~150~~120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~of the line~~ nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Generator interconnection Facilities connected to~~–~~ synchronous generators	Phase time overcurrent relay (51)	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – ~~150~~120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~of the line~~ nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% o the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – ~~150~~120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~of the line~~ nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts below				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to– asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Implementation Plan

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames. One time frame is provided if the Generator Owner determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner determines that its existing load-responsive protective relays require replacement. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner will need to: evaluate load-responsive protective relays applied on its Facilities; perform the applicable calculations required by the standard; and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement, the Generator Owner will need time to complete the evaluation in #4 above required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement, the Generator Owner will need time to complete the evaluation in #4 above required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.

Applicable Entities*

- Generator Owner

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

- None.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	**Jurisdictions where No Regulatory Approval is Required**
R1	Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Load-responsive protective relays which become applicable to the standard

Each Generator Owner that owns load-responsive protective relays that become applicable to this standard, not because of the actions of the Generator Owner including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard

Transition to Using Capability Reported to the Transmission Planner

Reliability Standard PRC-025-1 requires the Generator Owner to use “Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entities as specified by the Regional Reliability Organization.” PRC-025-1 includes the “Transmission Planner” to comport with the functional entity that receives the report of the Generator Owner’s gross Real Power capability pursuant to Reliability Standard MOD-025-2, which combines Reliability Standards MOD-024-1 and MOD-025-1.

Because Reliability Standards MOD-024-1 and MOD-025-1 require the Generator Owner to follow its Regional Reliability Organization’s procedures for reporting its gross Real and Reactive Power capability, respectively, Reliability Standard PRC-025-1 also includes the phrase “other entities as specified by the Regional Reliability Organization” so that the Generator Owner can remain compliant with PRC-025-1 and both MOD-024-1 and MOD-025-1 during the implementation period for MOD-025-2. This construction avoids a reliability gap and ambiguity within the PRC-025-1 standard regarding the value (gross Real Power capability) that is reported during the extended implementation plan for MOD-025-2.

Upon retirement of MOD-024-1 and MOD-025-1 and full compliance with MOD-025-2, entities will be reporting solely to the Transmission Planner. At that time, the reference to "other entities as specified by the Regional Reliability Organization" will be removed from PRC-025-1 since it will no longer be necessary or utilized by any functional entities following full implementation of MOD-025-2.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified in **bold blue with underlining for additions** and for ~~**deletions in bold red with a strikeout**~~.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1** **R1.** Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [Violation Risk Factor: High] [Time Horizon: Long-Term Planning]
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan~~implementation plan~~ addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames~~conditions~~. One time frame is provided if the Generator Owner determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner determines that its existing load-responsive protective relays require replacement. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan~~implementation plan~~ recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan~~implementation plan~~ assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner will need to: evaluate load-responsive protective relays applied on its Facilities;~~,~~ perform the applicable calculations required by the standard;~~,~~ and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement, the Generator Owner will need time to complete the evaluation in #~~(#~~4 above~~)~~ required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement, the Generator Owner will need time to complete the evaluation in #~~(#~~4 above~~)~~ required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.

Applicable Entities*

- Generator Owner~~*~~

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1 First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

- None.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on~~for~~ the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

- ~~For each load-responsive protective relay, where determined by the Generator Owner that replacement is not necessary, 48 months beyond the effective date of this standard.~~
- ~~For each load-responsive protective relay, where determined by the Generator Owner that replacement is necessary, 72 months beyond the effective date of this standard.~~

Load-responsive protective relays which become applicable to the standard

Each~~The~~ Generator Owner that owns~~owning~~ load-responsive protective relays that become applicable to this standard, not because of the actions of the Generator Owner including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard

Transition to Using Capability Reported to the Transmission Planner

Reliability Standard PRC-025-1 requires the Generator Owner to use "Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entities as specified by the Regional Reliability Organization." PRC-025-1 includes the "Transmission Planner" to comport with the functional entity that receives the report of the Generator Owner's gross Real Power capability pursuant to Reliability Standard MOD-025-2, which combines Reliability Standards MOD-024-1 and MOD-025-1.

Because Reliability Standards MOD-024-1 and MOD-025-1 require the Generator Owner to follow its Regional Reliability Organization's procedures for reporting its gross Real and Reactive Power capability, respectively, Reliability Standard PRC-025-1 also includes the phrase "other entities as specified by the Regional Reliability Organization" so that the Generator Owner can remain compliant with PRC-025-1 and both MOD-024-1 and MOD-025-1 during the implementation period for MOD-025-2. This construction avoids a reliability gap and ambiguity within the PRC-025-1 standard regarding the value (gross Real Power capability) that is reported during the extended implementation plan for MOD-025-2.

Upon retirement of MOD-024-1 and MOD-025-1 and full compliance with MOD-025-2, entities will be reporting solely to the Transmission Planner. At that time, the reference to "other entities as specified by the Regional Reliability Organization" will be removed from PRC-025-1 since it will no longer be necessary or utilized by any functional entities following full implementation of MOD-025-2.

~~first day of the first calendar quarter that is 48 months beyond the date such change is effected by an applicable regulatory authority, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

NERC

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified in **bold**~~the retirement or revision of a requirement, that text is~~ blue **with underlining for additions** and for **~~deletions in bold red with a strikeout~~**.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1** **R1.** Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [Violation Risk Factor: High] [Time Horizon: Long-Term Planning*]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, “Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The term, “while maintaining reliable fault protection” in Requirement R1, describes that the Generator Owner is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner must understand the applications of Attachment 1, Relay Settings, Table 1, Relay Loadability Evaluation Criteria (“Table 1”) in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner at the terminals of the generator, generator step-up (GSU) transformer, unit auxiliary transformer (UAT) and, where applicable, the Generator Owner’s generator interconnection Facility and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner’s interconnection facility (in some cases labeled a “transmission Facility” or “generator leads”) consists of Elements between the generator step-up transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard refers to these Facilities as “generator interconnection Facility(ies)” consistent with the work of the Project 2010-07 (Generator Requirements at the

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

Transmission Interface) drafting team. The following three figures clarify various considerations regarding the generator interconnection Facility.

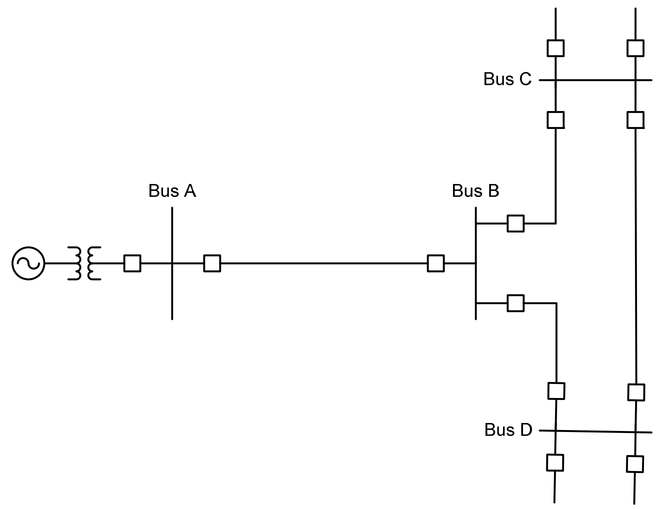


Figure 1. The line from Bus A to Bus B represents a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider or Transmission Owner owns these relays, they are responsible for them under PRC-023.

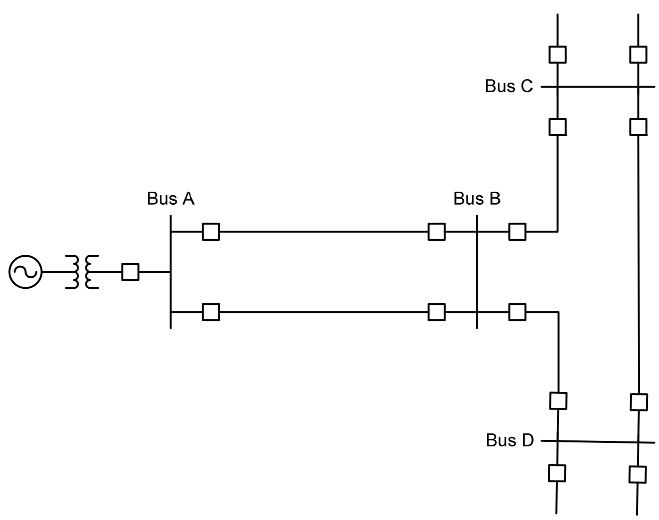


Figure 2. The parallel lines from Bus A to Bus B together represent a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider, Generator Owner, or Transmission Owner owns these relays, they are responsible for them under PRC-023.

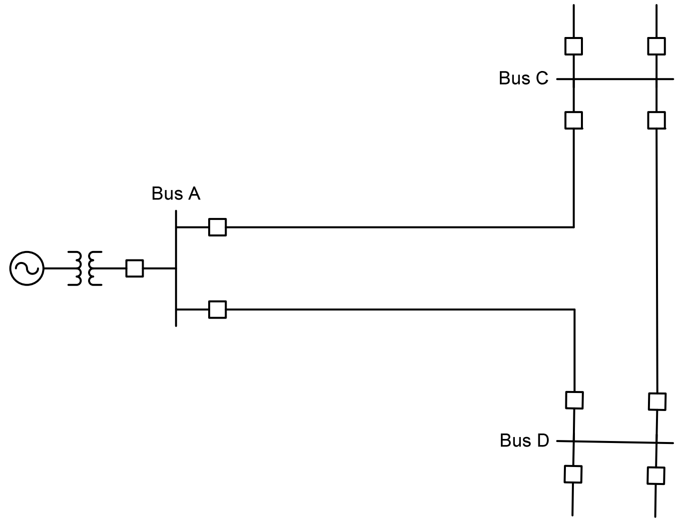


Figure 3. Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as generator interconnection Facilities. In this case, the Distribution Provider or Transmission Owner would be responsible for the load-responsive protective relays at the terminals under PRC-023.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column “Pickup Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the generator step-up transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (0.95 per unit) and 1b (0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (simulation) was developed to allow the Generator Owner to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19), for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with*

> *little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator megavoltampere (MVA) rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

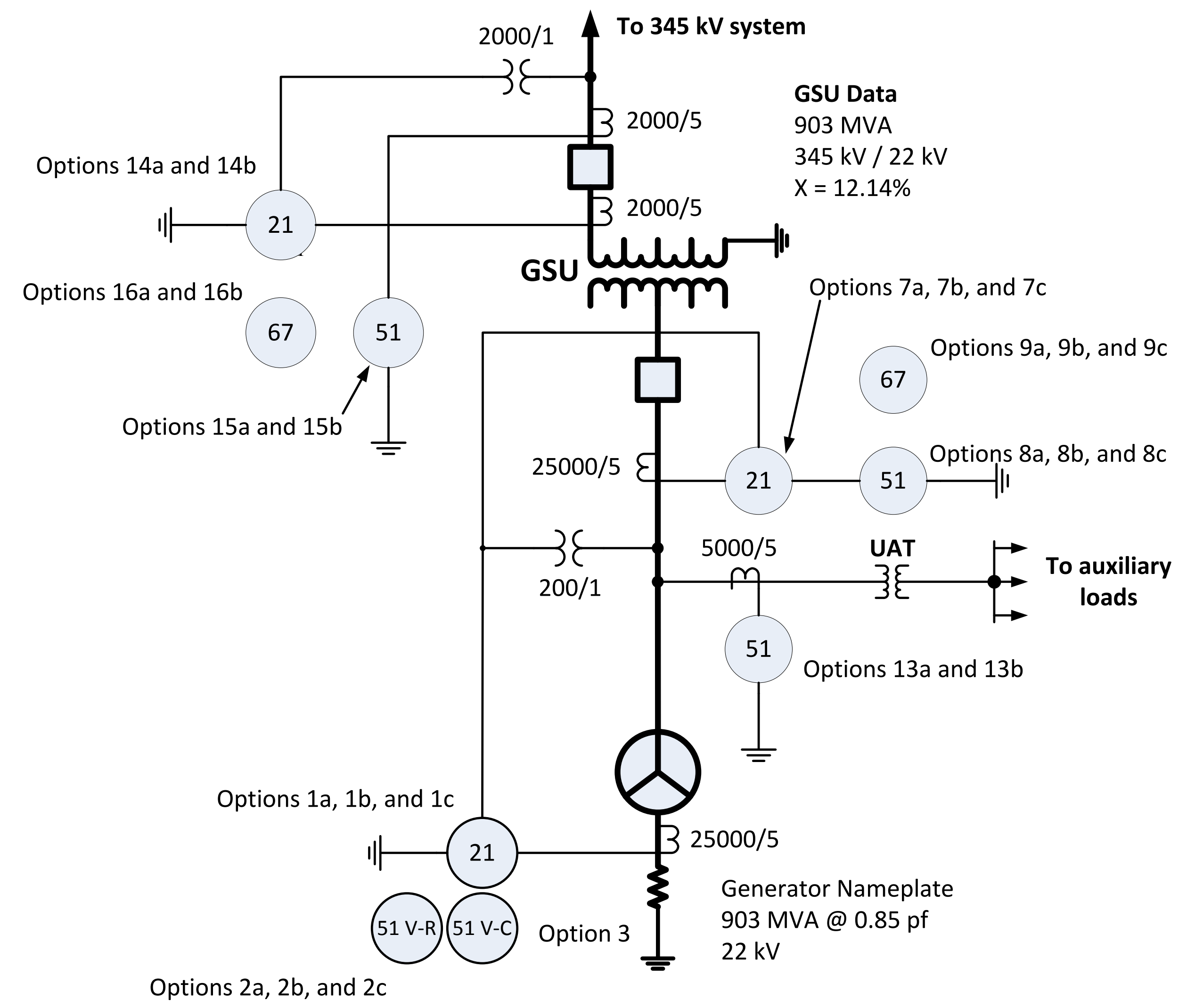


Figure 4. Relay Connection for corresponding synchronous options.

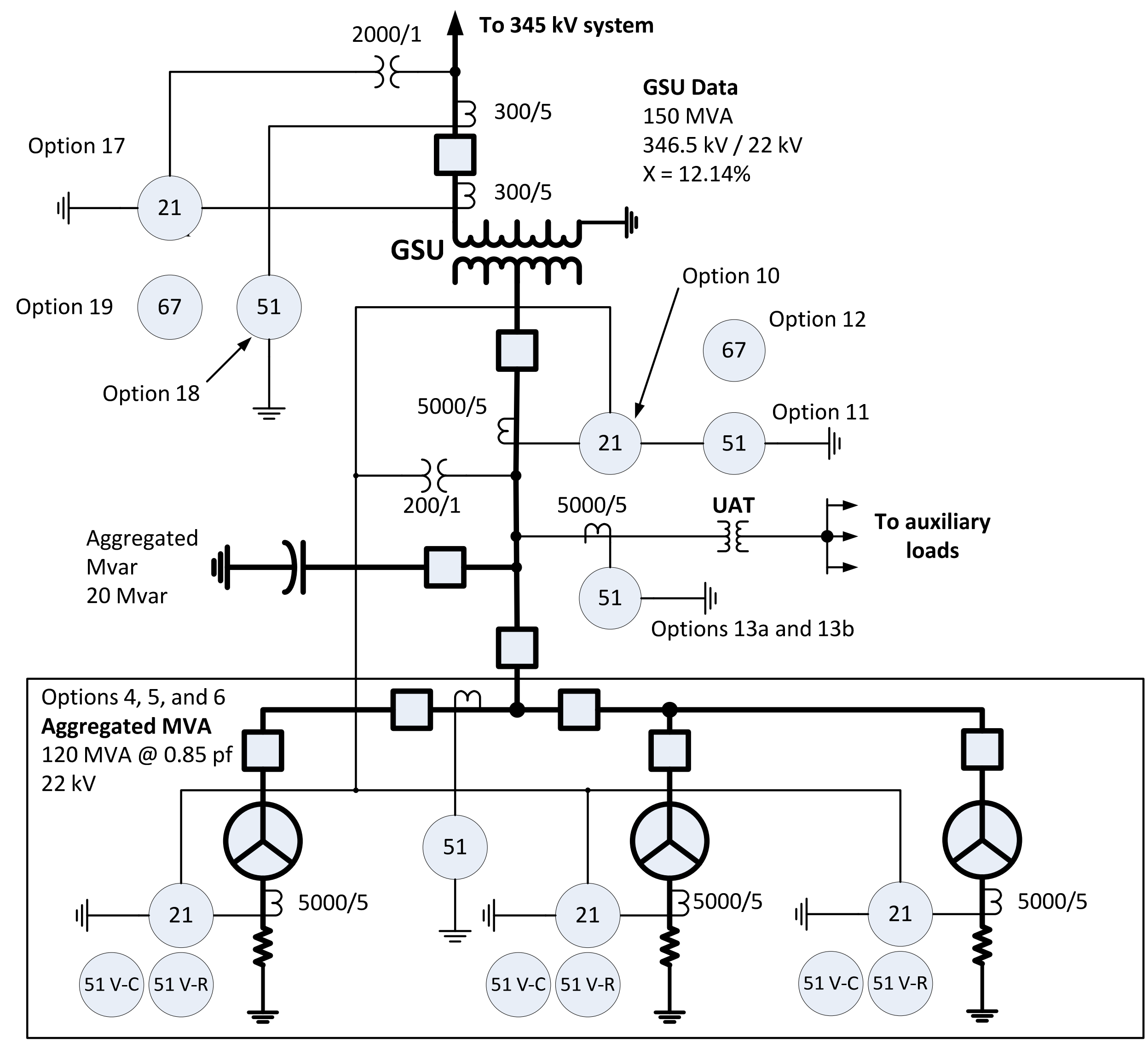


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power

achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power

achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power

achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the generator step-up transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the generator step-up transformer. Where the relay is connected on the high-side of the generator step-up transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer’s turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) ("UAT") that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying protecting UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are not a part of this standard. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating unit or plant.

Refer to the figures 6 and 7 below for example configurations:

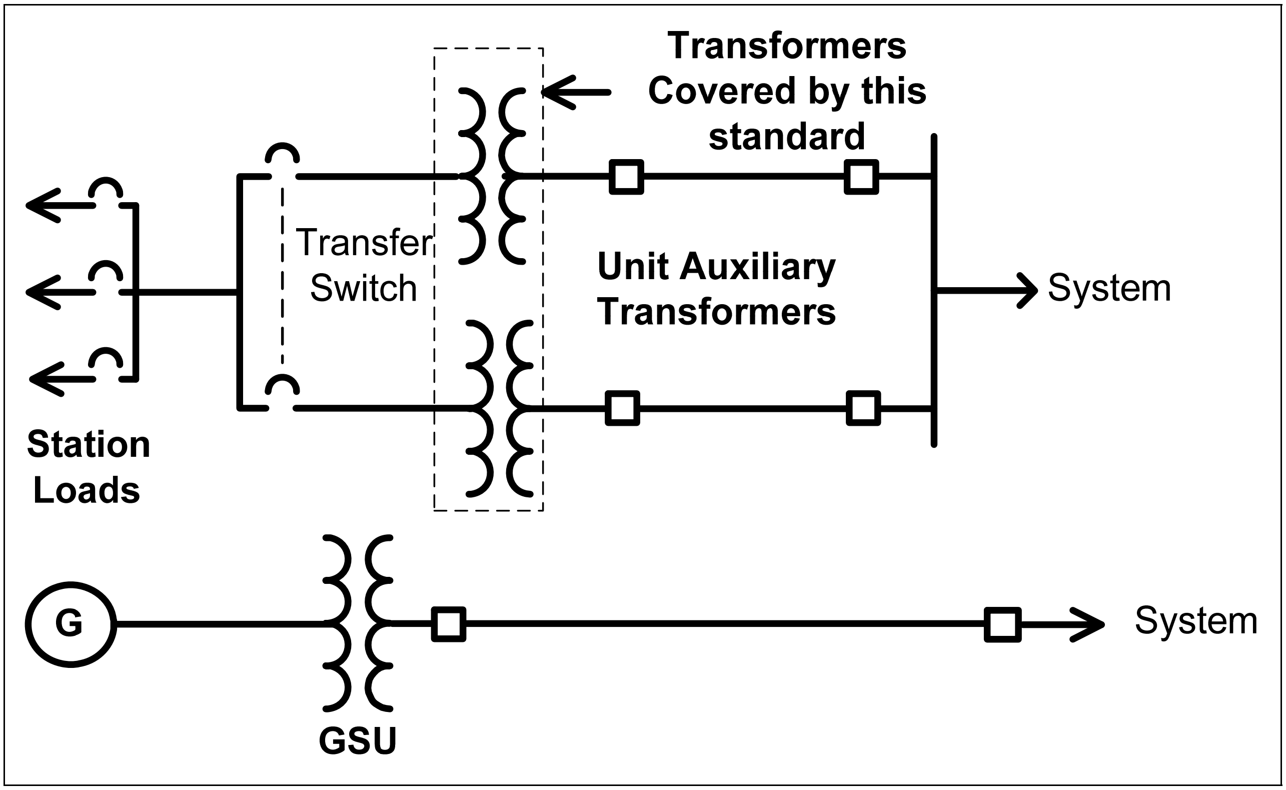


Figure-6 – Auxiliary Power System (independent from generator).

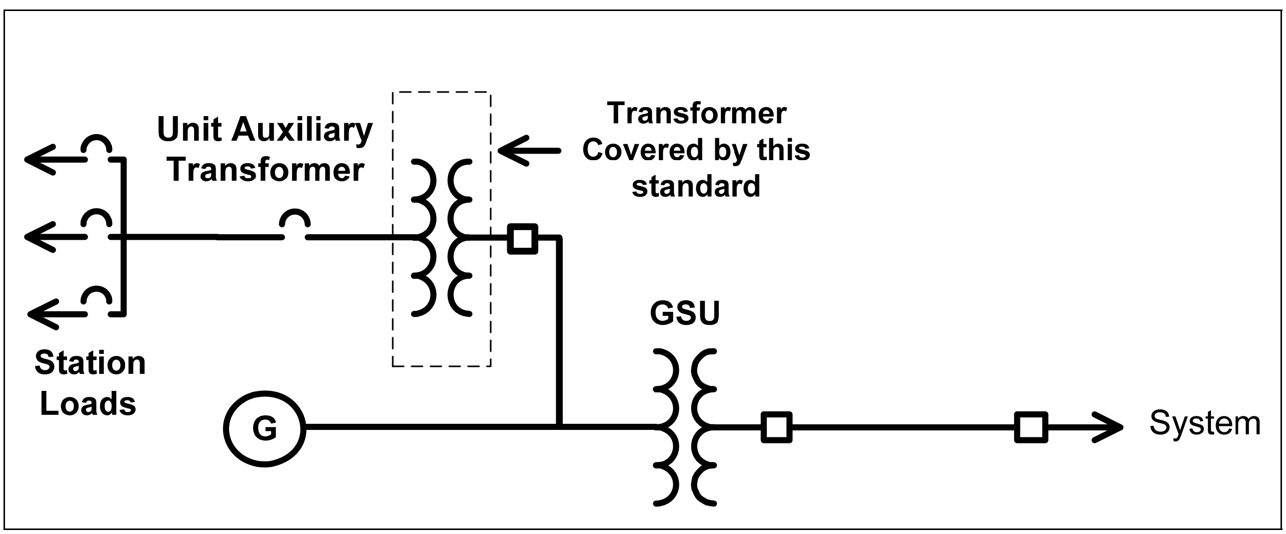


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected UAT load demand at the highest generator output. Although the nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization.

The performance of the UAT loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 14 is used for these relay as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator interconnection Facilities phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 15 is used for these relay as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator interconnection Facilities phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 16 is used for these relay as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the aggregate generation

MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate

MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\ nom} = 22\ kV$
Real Power output in MW as reported to the PC or TP:	$P_{reported} = 700.0\ MW$
Generator step-up transformer rating:	$MVA_{GSU} = 903\ MVA$
Generator step-up transformer impedance (903 MVA base):	$Z_{gsu} = 12.14\%$
Generator step-up transformer MVA base:	$MVA_{base} = 767.6\ MVA$
Generator step-up transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer ratio low-side:	$PT_{ratio} = \frac{200}{1}$
Potential transformer ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Auxiliary transformer nameplate:	$UAT_{nameplate} = 60\ MVA$
Auxiliary low-side voltage:	$V_{uat} = 13.8\ kV$
Auxiliary current transformer:	$CT_{uat} = \frac{5000}{5}$
Current transformer High Voltage CT ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive power output of static reactive device:	$MVAR_{static} = 20\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 120\ MVA$
	$pf = 0.85$

Example Calculations.	
Asynchronous current transformer ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous current transformer High Voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a
Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < \ 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance (21) directional toward the Transmission system relay. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance (21) directional toward the Transmission system relay.

Real Power output (P):

Eq. (9) $$P = \ GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

Example Calculations: Options 1b and 7b

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Example Calculations: Options 1b and 7b

Eq. (15)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 1b and 7b

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°$$

Primary Impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\Omega}{\cos(85.0^{\circ} - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < \ 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

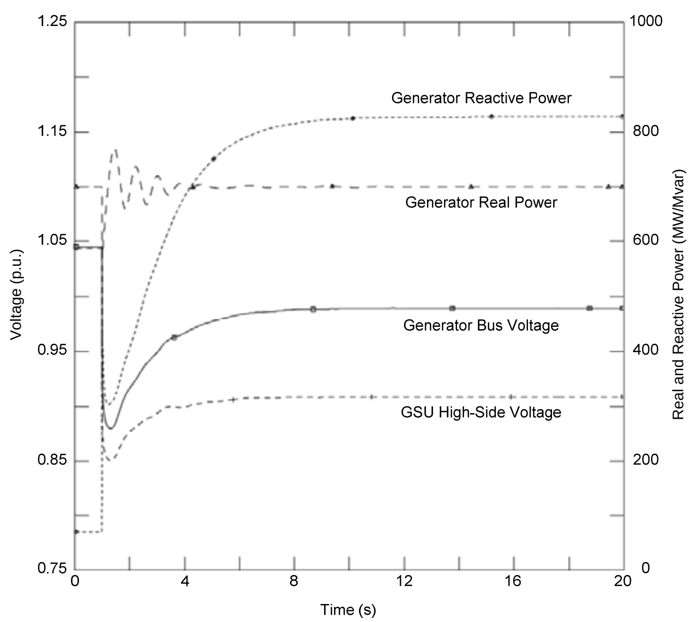
In this simulation the following values are derived:

Q = 829.3 Mvar

V_{bus} = 0.990 = 21.78 kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW



Apparent power (S):

Eq. (24) $S = P_{reported} + jQ$

Example Calculations: Options 1c and 7c

$$S = 700.0\ MW + j829.3\ Mvar$$

$$S = 1085.2\angle 49.8°$$

Primary Impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.78\ kV)^2}{1085.2\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^{\circ} - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} <\ 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Example Calculations: Option 2a

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.477 \text{ A}$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477 \text{ A} \times 1.15$$

$$I_{\sec limit} > 8.598 \text{ A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Option 2b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = \left|V_{low-side}\right| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ \text{MVA}$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ \mathrm{A}$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ \mathrm{A} \times 1.15$$

$$I_{\sec limit} > 8.178\ \mathrm{A}$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

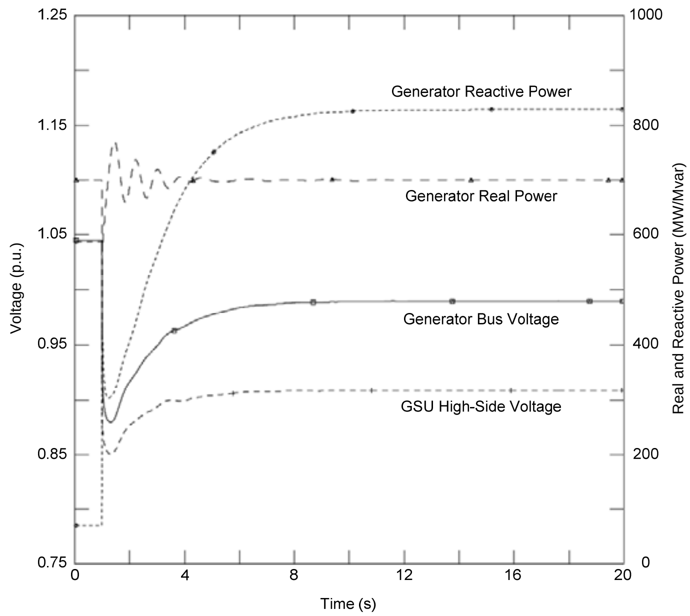
Q = 829.3 Mvar

V_{bus} = 0.990 = 21.78 kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{reported} + jQ$

$S = 700.0\ MW + j829.3\ Mvar$

$S = 1085.2\angle 49.8°$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1085.2\ MVA}{1.73 \times 21.78\ kV}$$

$$I_{pri} = 28801\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28801\ \text{A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.760\ \text{A}$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.760\ \text{A} \times 1.15$$

$$I_{\sec limit} > 6.624\ \text{A}$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

Example Calculations: Options 3 and 6

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Options 4 and 10
This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych\_namplate} \times pf$$

$$P = 120\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = MVAR_{static} + GEN_{Async\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 20\ Mvar + 63.2\ Mvar$$

$$Q = 83.2\ Mvar$$

Options 4 and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Options 4 and 10

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \ \Omega}{0.6972}$$

$$Z_{max} <\ 20.109\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage-restrained relay. In this application it was assumed 20Mvar of static compensation was added.

Real Power output (P):

Eq. (64) $$P = GEN_{Asynch\_namplate} \times pf$$

$$P = 120\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 20\ Mvar + 63.2\ Mvar$$

$$Q = 83.2\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ \ A$$

Example Calculations: Option 5

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2° \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \text{ A}$$

To satisfy the 130% margin in Option 5:

Eq. (70) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2° \text{ A} \times 1.30$$

$$I_{\text{sec}\,limit} > 4.52\angle -39.2° A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous and synchronous generation (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added.

Synchronous Generation

Real Power output (P_{sync}):

Eq. (71) $$P_{sync} = GEN_{Synch\_nameplate} \times pf$$

$$P_{sync} = 903\ MVA \times 0.85$$

$$P_{sync} = 767.6\ MW$$

$$P_{sync-reported} = 700\ MW$$

Reactive Power Output (Q_{sync})

Eq. (72) $$Q_{sync} = 150\% \times P_{synch}$$

$$Q_{sync} = 150\% \times 767.6\ MW$$

$$Q_{sync} = 1151.3\ MW$$

Apparent Power (S_{sync})

Eq. (73) $$S_{sync} = P_{sync-reported} + jQ_{synch}$$

Example Calculations: Options 7a and 10

$$S_{sync} = 700MW + j1151.3\ MVAR$$

Asynchronous

Real Power output (P_{async}):

Eq. (74) $$P_{async} = GEN_{Asynch\_namplate} \times pf$$

$$P_{async} = 120\ MVA\ \times 0.85$$

$$P_{async} = 102.0\ MW$$

Reactive Power output (Q_{async}):

Eq. (75) $$Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{async} = 20\ Mvar + 63.2\ Mvar$$

$$Q_{async} = 83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator bus voltage, however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (V_{gen}):

Eq. (76) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (77) $$S = 1.15 \times \left(P_{sync-reported} + jQ_{sync}\right) + 1.30 \times (P_{async} + jQ_{async})$$

$$S = 1.15 \times (700\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (78) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

Secondary impedance (Z_{sec}):

Eq. (79) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\,\Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\,\Omega$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 and the asynchronous apparent power has been multiplied by 1.30 in Equation 77 to satisfy the margin requirements in Options 7a and 10:

Eq. (80) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\,\Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (81) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \ \Omega}{0.881}$$

$$Z_{max} <\ 7.17\angle 85.0°\,\Omega$$

Example Calculations: Options 8a, 9a, 11, and 12

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of static compensation was added. The CTs are located on the low-side of the GSU.

Synchronous Generation

Real Power output (P_{sync}):

Eq. (82) $$P_{sync} = GEN_{Synch\_nameplate} \times pf$$

$$P_{sync} = 903\ MVA \times .85$$

$$P_{sync} = 767.6\ MW$$

$$P_{sync-reported} = 700\ MW$$

Reactive Power Output (Q_{sync})

Eq. (83) $$Q_{sync} = 150\% \times P_{synch}$$

$$Q_{sync} = 150\% \times 767.6\ MW$$

$$Q_{sync} = 1151.3\ Mvar$$

Apparent Power (S_{sync})

Eq. (84) $$S_{sync} = P_{sync-reported} + jQ_{synch}$$

$$S_{sync} = 700\ MW + j1151.3\ Mvar$$

$$S_{sync} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (85) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary Current ($I_{pri-sync}$):

Eq. (86) $$I_{pri-sync} = \frac{1.15 \times S_{sync}^{*}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ \mathrm{A}$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous

Real Power output (P_{async}):

Eq. (87) $$P_{async} = GEN_{Asynch\_namplate} \times pf$$

$$P_{async} = 120\ MVA\ \times 0.85$$

$$P_{async} = 102.0\ MW$$

Reactive Power output (Q_{async}):

Eq. (88) $$Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{async} = 20\ Mvar + 63.2\ Mvar$$

$$Q_{async} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (89) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{async}):

Eq. (90) $$S_{async} = 1.30\ \times (P_{async} + jQ_{async})$$

$$S_{async} = 1.30\ \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{async} = 171.1\ \angle 39.2°\ MVA$$

Primary Current ($I_{pri-async}$):

Eq. (91) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{(171.1\ \angle -39.2°\ MVA)}{1.73\ \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ \text{A}$$

Secondary current (I_{sec}):

Eq. (92) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061\angle -58.7°\text{ A}}{\frac{25000}{5}} + \frac{4755\angle -39.2°\text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\text{ A}$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 in Equation 86 and the asynchronous has been multiplied by 1.30 in Equation 90.

Eq. (93) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\text{ A} \times 1.00$$

$$I_{\sec limit} > 9.514\angle -56.8°\ A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

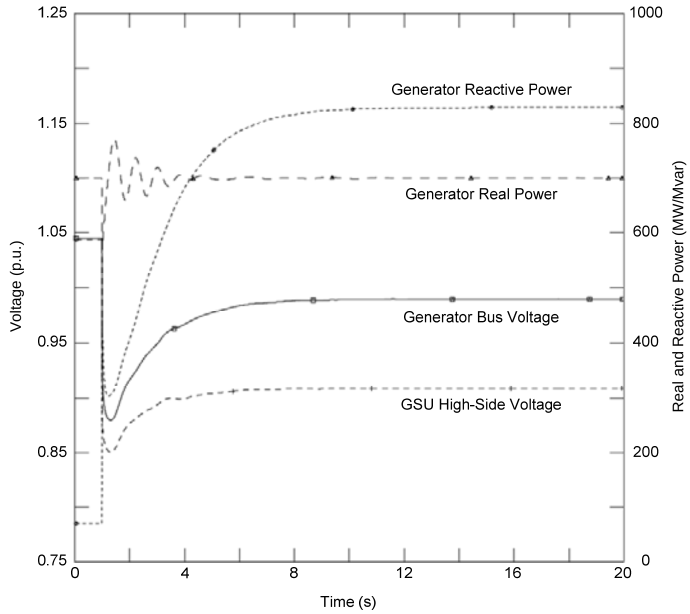
Q = 829.3 Mvar

V_{bus} = 0.990 = 21.78 kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW

Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (94) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j829.3\ Mvar$$

$$S = 1085.2\angle 49.8°$$

Primary current (I_{pri}):

Eq. (95) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1085.2\ MVA}{1.73 \times 21.78\ kV}$$

$$I_{pri} = 28801\ A$$

Secondary current (I_{sec}):

Eq. (96) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28801\text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.760\text{ A}$$

Example Calculations: Options 8c and 9c

To satisfy the 115% margin in Option 8c:

Eq. (97) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.760\text{ A} \times 1.15$$

$$I_{\sec limit} > 6.624\text{ A}$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added.

Real Power output (P):

Eq. (98) $P = GEN_{Asynch\_namplate} \times pf$

$$P = 120\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (99) $Q = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 20\ Mvar + 63.2\ Mvar$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (100) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (101) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Example Calculations: Options 11 and 12

Primary current (I_{pri}):

Eq. (102) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (103) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (104) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization.

Primary current (I_{pri}):

Eq. (105) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Example Calculations: Options 13a and 13b

Secondary current (I_{sec}):

Eq. (106) $$I_{sec} = \frac{I_{pri}}{CT_{uat}}$$

$$I_{sec} = \frac{2510.2\text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

To satisfy the 150% margin in Option 13a:

Eq. (107) $$I_{\text{sec}\,limit} > I_{sec} \times 150\%$$

$$I_{\text{sec}\,limit} > 2.51\text{ A} \times 1.50$$

$$I_{\text{sec}\,limit} > 3.77\text{ A}$$

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

Real Power output (P):

Eq. (108) $$P = GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (109) $$Q = 120\% \times P$$

$$Q = 1.2 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (110) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Example Calculations: Option 14a

Apparent power (S):

Eq. (111) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (112) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (113) $Z_{sec} = Z_{pri} \times \frac{CT_{hv}}{PT_{hv}}$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (114) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (115) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{12.928\Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < \ 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

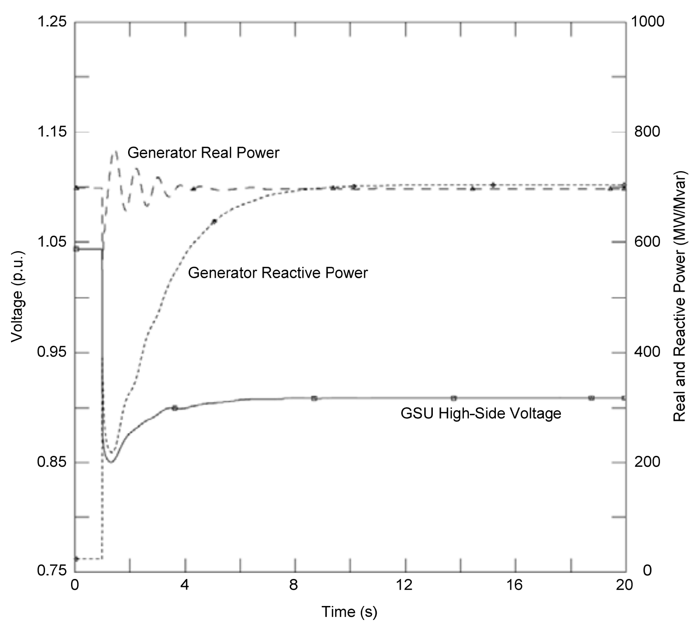
In this simulation the following values are derived:

Q = 704.4 Mvar

V_{bus} = 0.908 = 313.3 kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW



Example Calculations: Option 14b

Apparent power (S):

Eq. (116) $$S = P_{reported} + jQ$$

$$S = 700.0\ MW + j704.4\ Mvar$$

$$S = 993.1\angle 45.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.2°$$

Primary impedance (Z_{pri}):

Eq. (117) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{993.1\angle -45.2°\ MVA}$$

$$Z_{pri} = 98.84\angle 45.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (118) $$Z_{sec} = Z_{pri} \times \frac{CT_{hv}}{PT_{hv}}$$

$$Z_{sec} = 98.84\angle 45.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.84\angle 45.2°\ \Omega \times 0.2$$

$$Z_{sec} = 19.77\angle 45.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (119) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.77\angle 45.2°\ \ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.19\angle 45.2°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (120) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.19\ \Omega}{\cos(85.0° - 45.2°)}$$

Example Calculations: Option 14b

$$Z_{max} < \frac{17.19\ \Omega}{0.768}$$

$$Z_{max} < \ 22.38\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU.

Real Power output (P):

Eq. (121) $P = \ GEN_{Synch\_namplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (122) $Q = 120\% \times P$

$$Q = 1.2 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (123) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (124) $S = P_{reported} + jQ$

$$S = 700\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (125) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\ \mathrm{MVA}}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (126) $$I_{sec} = \frac{I_{pri}}{CT_{hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ \mathrm{A}}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ \mathrm{A}$$

To satisfy the 115% margin in Option 15a:

Eq. (127) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ \mathrm{A} \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ \mathrm{A}$$

Example Calculations: Options 15b and 16b

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

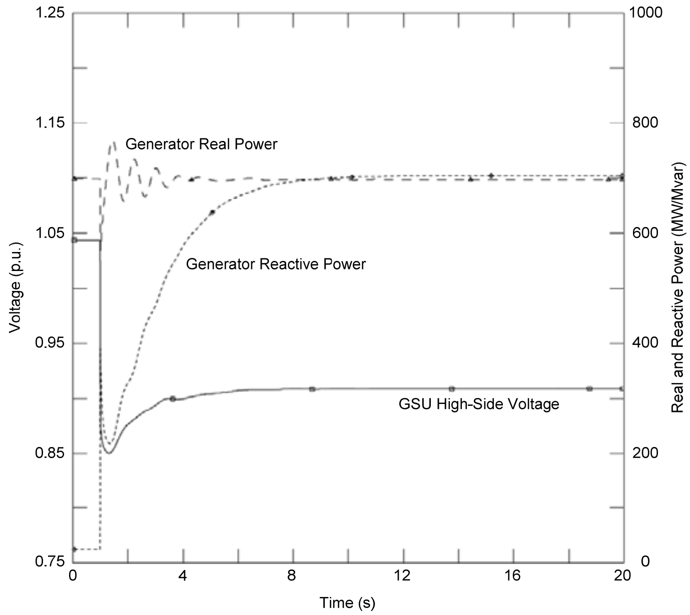
Q = 704.4 Mvar

V_{bus} = 0.908 = 313.3 kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (128) $S = P_{reported} + jQ$

$$S = 700\ MW + j704.4\ Mvar$$

$$S = 993.1\angle 45.2°\ MVA$$

Primary current (I_{pri}):

Eq. (129) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{993.1\angle -45.2°\ \text{MVA}}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1832.2\angle -45.2°\ A$$

Secondary current (I_{sec}):

Eq. (130) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}}$

$$I_{sec} = \frac{1832.2\angle -45.2°\ \text{A}}{\frac{2000}{5}}$$

$$I_{sec} = 4.580\ \angle -45.2°\ \text{A}$$

Example Calculations: Options 15b and 16b

To satisfy the 115% margin in Option 15b:

Eq. (131) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 4.580 \angle -45.2° \times 1.15$

$I_{\sec limit} > 5.267 \angle -45.2°$ A

Example Calculations: Option 17

Option 17 represents the calculation for an asynchronous generation interconnection facility applying a phase distance (21) - directional toward the Transmission. In this application it was assumed 20 Mvar of static compensation was added.

Real Power output (P):

Eq. (132) $P_{async} = GEN_{Asynch\_namplate} \times pf$

$P_{async} = 120\ MVA \times 0.85$

$P_{async} = 102.0\ MW$

Reactive Power output (Q):

Eq. (133) $Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$

$Q_{async} = 20\ Mvar + 63.2\ Mvar$

$Q_{async} = 83.2\ Mvar$

Option 17, Table 1 – Bus Voltage, calls for a 1.00 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (134) $V_{bus} = 1.00\ p.u. \times V_{nom}$

$V_{gen} = 1.00 \times 345\ kV$

$V_{gen} = 345.0\ kV$

Apparent power (S):

Eq. (135) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Example Calculations: Option 17

Primary impedance (Z_{pri}):

Eq. (136) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (137) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (138) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (139) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} <\ 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for a generation interconnection Facility applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 19 may also be applied here for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 20 Mvar of static compensation was added.

Real Power output (P):

Eq. (140) $P = GEN_{Asych\_namplate} \times pf$

$$P = 120\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (141) $Q = MVAR_{static} + GEN_{Asych\_namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 20\ Mvar + 63.2\ Mvar$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (142) $V_{nom} = 1.0\ p.u.\times V_{nom}$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (143) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (144) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (145) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2° \text{ A}}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2° \text{ A}$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (146) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.675\angle -39.2° \text{ A} \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.778\angle -39.2° \text{ A}$$

End of calculations

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The term, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner ~~("responsible entity")~~ is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generati~~o~~ng unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner~~responsible entity~~ consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible~~necessary~~ to meet this purpose by replacing~~replace~~ the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner~~responsible entity~~ must understand the applications of Attachment 1, Relay Settings, Table 1, Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner at the terminals of the generator, generator step-up (GSU) transformer, unit auxiliary transformer (UAT) and, where applicable, the Generator Owner's generator interconnection Facility and Elements utilized in the aggregation of dispersed power producing resources.

The ~~drafting team recognizes that some~~ Generator Owner's~~Owners own an~~ interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the generator step-up transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

refers to ~~In~~ these ~~cases, the Generator Owners own sole-use~~ Facilities as “generator interconnection Facility(ies)” consistent with~~that are connected to~~ the work~~boundary~~ of the Project 2010-07 (~~interconnected system. Load-responsive protective relays applied by the~~ Generator Requirements~~Owner~~ at the Transmission Interface) drafting team. The following three figures clarify various considerations regarding the generator interconnection Facility.

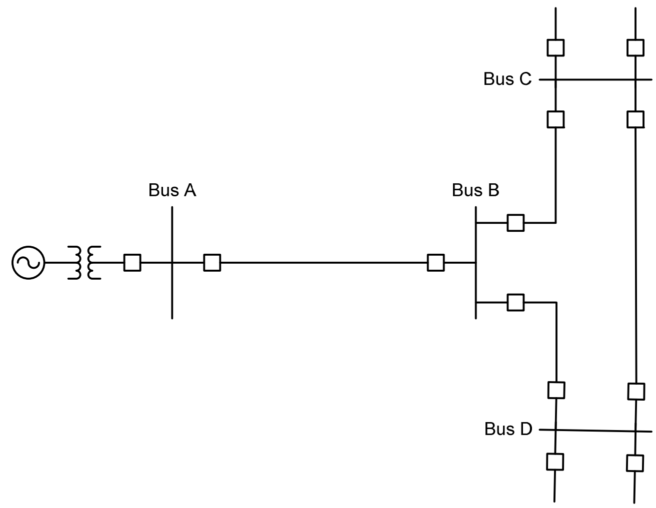


Figure 1. The line from Bus A to Bus B represents a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider or Transmission Owner owns these relays, they are responsible for them under PRC-023.

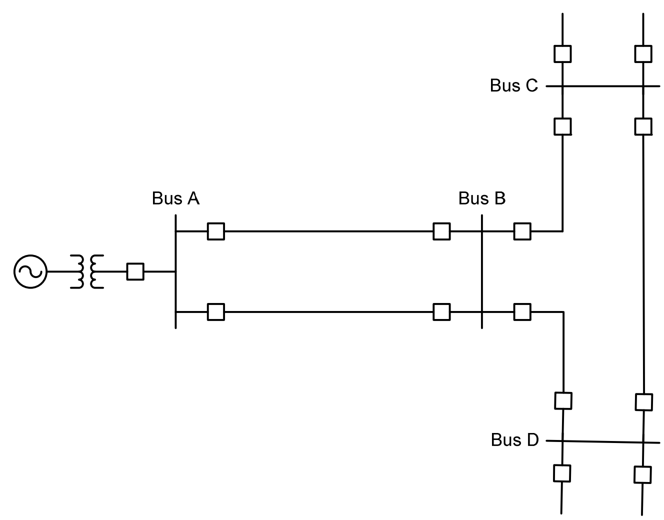


Figure 2. The parallel lines from Bus A to Bus B together represent a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider, Generator Owner, or Transmission Owner owns these relays, they are responsible for them under PRC-023.

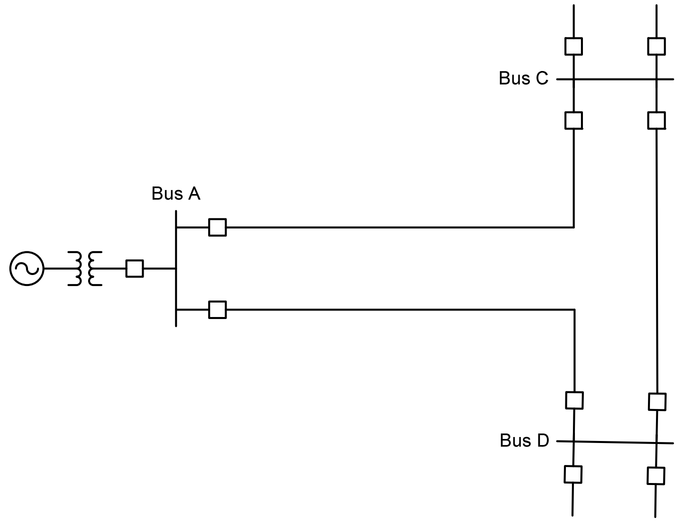


Figure 3. Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as generator interconnection Facilities. In this case, the Distribution Provider or Transmission Owner would be responsible for the load-responsive protective relays at the terminals under PRC-023.

Elements utilized~~terminals of these Facilities to protect these interconnection Facilities are included~~ in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This~~scope of this~~ standard is also applicable to unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column "Pickup Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the generator step-up transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (0.95 per unit) and 1b (0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (simulation) was developed to allow the Generator Owner~~responsible entity~~ to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19), for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner~~responsible entity~~ who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing~~megawatts as reported to the Planning Coordinator or Transmission Planner~~.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generati~~o~~ng units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with*

> *little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps~~restrict~~ the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1~~these~~ options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator megavoltampere (MVA) rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generati~~o~~ng units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is~~are~~ similar. Note that the Table 1setting~~setting~~ criteria established within the Table 1~~these~~ options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1~~these~~ options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

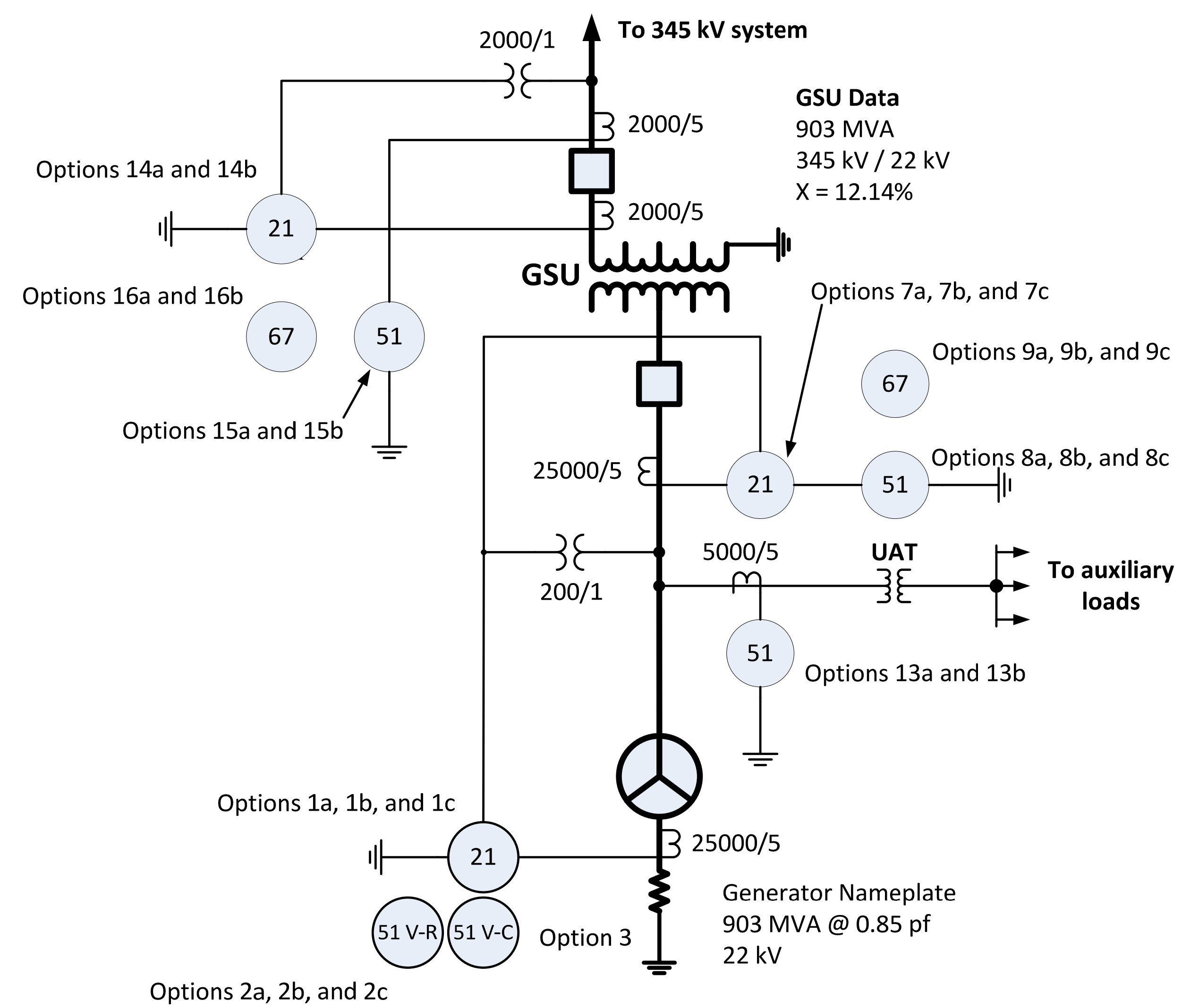


Figure 4. Relay Connection for corresponding synchronous options.

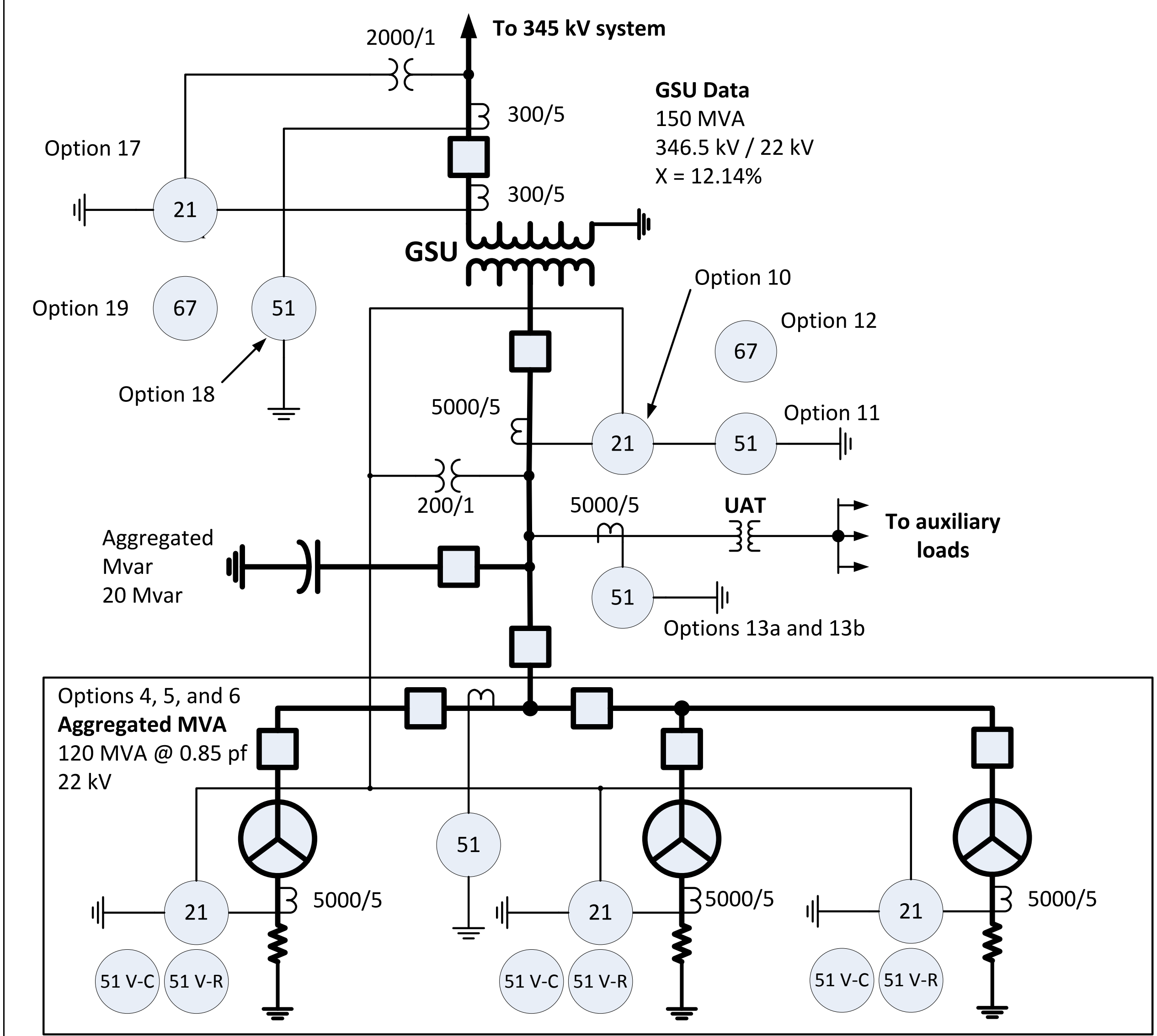


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a ~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. ~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices.

This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing.~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers.

Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the~~or~~ high-side of the generator step-up transformer, use Option 15 ~~of a synchronous generator~~.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing.~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing.~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the generator step-up transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11~~Options 11a and 11b~~)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for~~11a, address those~~ generator step-up transformers applying~~transformer~~ phase time overcurrent relays ~~installed~~ on asynchronous generators that are connected to the ~~low-side (i.e.,~~ generator-side~~)~~ of the generator step-up transformer. Where the relay is connected~~of an asynchronous generator, and Option 11b addresses those relays installed~~ on the high-side ~~(i.e., line-side)~~ of the generator step-up transformer, use Option 18~~of an asynchronous generator~~.

Option 11~~11a~~ calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer.~~, for overcurrent relays installed on the low-side.~~ The generator bus voltage ~~drop across the generator step-up transformer~~ is calculated by multiplying~~based on~~ a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times~~and accounts for~~ the turns ratio of the generator step-up transformer (excluding the impedance).~~.~~ This is a simple calculation that approximates the stressed system conditions.

Since~~Where~~ the relay current is supplied from the generator bus, ~~Option 11a,~~ it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio. ~~Where the relay current is supplied from the high-side of the transformer, it is necessary to assess loadability using the high-side nominal voltage in Option 11b.~~

For Option 11~~Options 11a and 11b~~, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. Where the relay is connected on the high-side of the generator step-up transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) ("UAT")that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying protecting UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays~~ing~~ applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are not a part of this standard. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating unit or plant.

Refer to the figures 6 and 7 below for example configurations:

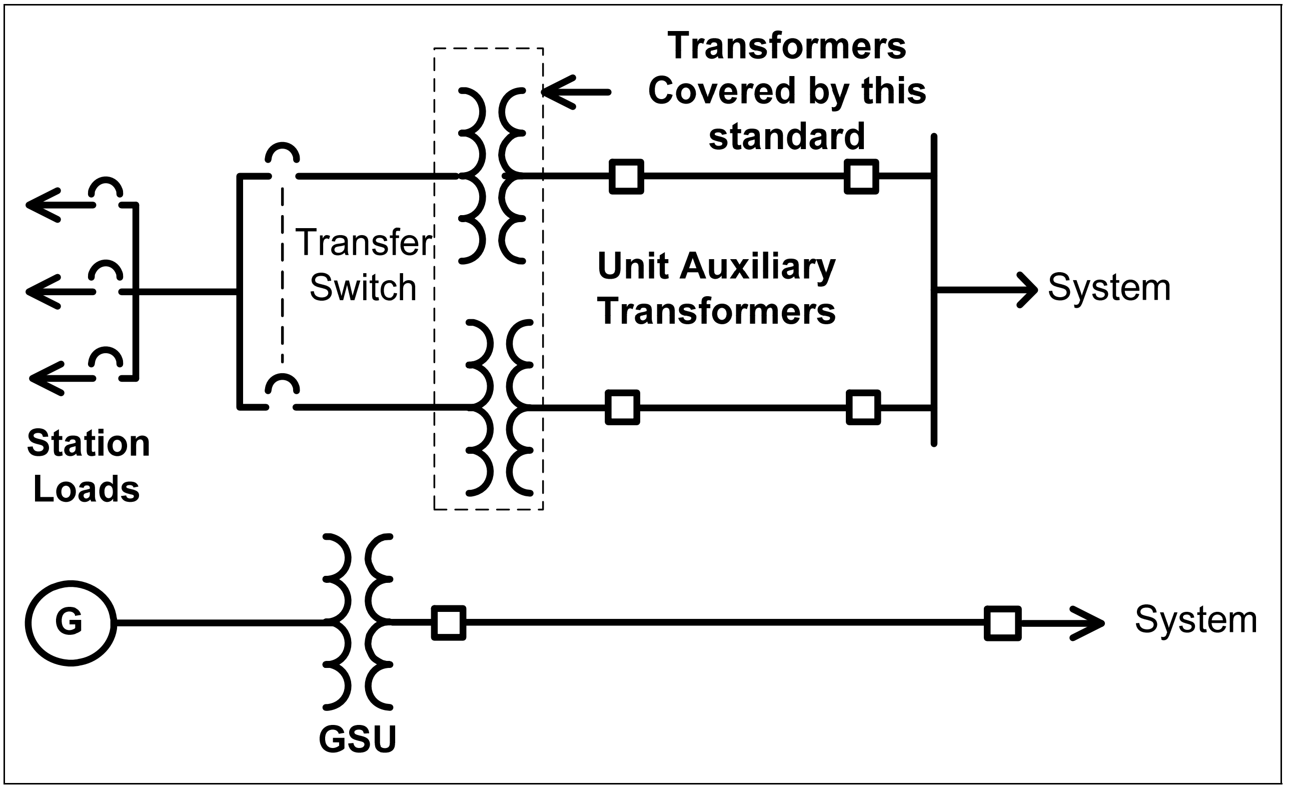


Figure-6~~1~~ – Auxiliary Power System (independent from generator).~~)~~

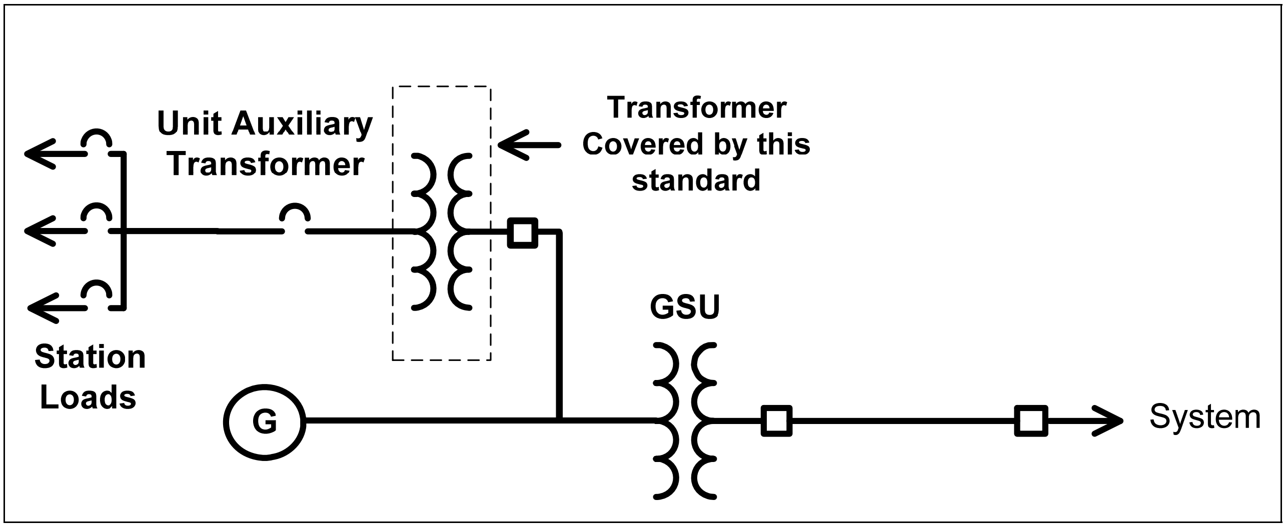


Figure-~~2~~7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected UAT load demand at the highest generator output. Although the nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization.

The performance of the UAT loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 14 is used for these relay as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option~~s~~ 14a reflects~~and 14b, reflect~~ a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator interconnection Facilities~~step-up transformer~~ phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120~~150~~ percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 15 is used for these relay as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option~~s~~ 15a reflects~~and 15b, reflect~~ a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator interconnection Facilities~~step-up transformer~~ phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120~~150~~ percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120~~100~~ percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 16 is used for these relay as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option~~s~~ 16a reflects~~and 16b, reflect~~ a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities~~generator step-up transformer~~ phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120~~150~~ percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the impedance from the maximum aggregate nameplate MVA.~~.~~ Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power ~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power ~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate}$ $\cancel{GEN_{nameplate}} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\ nom}\cancel{V_{gen}} = 22\ kV$
Real Power output in MW as reported to the PC or TP:	$P_{reported} = 700.0\cancel{767.6}\ MW$
Generator step-up transformer rating:	$MVA_{GSU} = 903\ MVA$
Generator step-up transformer impedance (903 MVA base):	$Z_{gsu} = 12.14\%$
Generator step-up transformer MVA base:	$MVA_{base} = 767.6\ MVA$
Generator step-up transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer ratio low-side:	$PT_{ratio} = \frac{200}{1}$
Potential transformer ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Auxiliary transformer nameplate:	$UAT_{nameplate} = 60\ MVA$
Auxiliary low-side voltage:	$V_{uat} = 13.8\ kV$
Auxiliary current transformer:	$CT_{uat} = \frac{5000}{5}$
Current transformer~~Transformer~~ High Voltage CT ratio:	$CT_{ratio\_hv}\cancel{CT_{HV}} = \frac{2000}{5}$
Reactive p~~P~~ower output of static reactive device:	$MVAR_{static} = 20\cancel{100}\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 120\ MVA$

Example Calculations.	
	$pf = 0.85$
Asynchronous current transformer ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous current transformer High Voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a
Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u.\ \times V_{nom} \times GSU_{ratio}\cancel{GSU_{ratio}}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{reported} + jQ$$

$$S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58\cancel{1383}.7\cancel{\angle 56.3}°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}\cancel{\frac{(20.81\ kV)^2}{1383.7\angle -56.3°\ MVA}}$$

$$Z_{pri} = 0.321\angle 58.7\cancel{3130\angle 56.3}°\ \Omega$$

Example Calculations: Option 1a

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7\cancel{3130\angle 56.3}° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}} \cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 0.321\angle 58.7\cancel{3130\angle 56.3}° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7\cancel{.8238\angle 56.3}° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7° \Omega}{1.15} \cancel{\frac{7.8238\angle 56.3° \, \Omega}{1.15}}$$

$$Z_{\sec limit} = 6.9873\angle 58.7\cancel{8033\angle 56.3}° \, \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873 \Omega}{\cos(85.0° - 58.7°)} \cancel{\frac{6.8033 \, \Omega}{\cos(85.0° - 56.3°)}}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896} \cancel{\frac{6.8033 \, \Omega}{0.8771}}$$

$$Z_{max} < 7.7937\cancel{561}\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance (21) directional toward the Transmission system relay. This option requires calculating low-side voltage taking into account voltage drop across the GSU~~generator step-up~~ transformer. Similarly these calculations may be applied to Option 7b for GSU~~generator step-up~~ transformers applying a phase distance (21) directional toward the Transmission system relay.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_namplate} \cancel{GEN_{namplate}} \times pf$$

Example Calculations: Options 1b and 7b

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{reported}}{MVA_{base}} \cancel{\frac{P}{MVA_{base}}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA} \cancel{\frac{767.6\ MW}{767.6\ MVA}}$$

$$P_{pu} = \cancel{1.}0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Example Calculations: Options 1b and 7b

Use the formula below; calculate the low-side GSU~~generator step-up~~ transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat~~Repeat~~ the calculation as~~if~~ necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14)

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu}\times|X_{pu}|\right)}{\left(|V_{low-side}|\times|V_{high-side}|\right)}\right] \cancel{\frac{\sin^{-1}\left(P_{pu}\times|X_{pu}|\right)}{\left(|V_{low-side}|\times|V_{high-side}|\right)}}$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91\times 0.1032)}{(0.95\times 0.85)}\right] \cancel{\frac{\sin^{-1}(1.0\times 0.1032)}{(0.95\times 0.85)}}$$

$$\cancel{\theta_{low-side} = \frac{5.92^\circ}{0.8075}}$$

$$\theta_{low-side} = 6.7\cancel{3}^\circ$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}|\times\cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2\times\cos^2(\theta_{low-side}) + 4\times Q_{pu}\times X_{pu}}}{2} \cancel{|V_{low-side}| = \frac{|V_{high-side}|\times\cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2\times\cos(\theta_{low-side})^2 + 4\times Q_{pu}\times X_{pu}}}{2}}$$

$$|V_{low-side}| = \frac{|0.85|\times\cos(6.7^\circ) \pm \sqrt{|0.85|^2\times\cos^2(6.7^\circ) + 4\times 1.5\times 0.1032}}{2} \cancel{\frac{|0.85|\times\cos(7.3^\circ) \pm \sqrt{|0.85|^2\times\cos(7.3^\circ)}}{2}}$$

$$|V_{low-side}| = \frac{|0.85|\times 0.9931 \pm \sqrt{0.7225\times 0.9864 + 0.6192}}{2} \cancel{\frac{|0.85|\times 0.9918 \pm \sqrt{0.7225\times 0.9837 + 0.6192}}{2}}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2} \cancel{\frac{0.8430 \pm 1.1532}{2}}$$

$$|V_{low-side}| = 0.999\cancel{8}1\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.999~~8~~1 per unit for the second iteration:

Eq. (16)

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu}\times|X_{pu}|\right)}{\left(|V_{low-side}|\times|V_{high-side}|\right)}\right] \cancel{\frac{\sin^{-1}\left(P_{pu}\times|X_{pu}|\right)}{\left(|V_{low-side}|\times|V_{high-side}|\right)}}$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91\times 0.1032)}{(0.9991\times 0.85)}\right] \cancel{\frac{\sin^{-1}(1.0\times 0.1032)}{(0.9981\times 0.85)}}$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = 6.3°$$

$$\cancel{\frac{5.92°}{0.8484}}$$

$$\cancel{\theta_{low-side} = 7.0°}$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \cancel{|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2} \cancel{\frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°}}{2}}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2} \cancel{\frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2} \cancel{\frac{0.8437 \pm 1.1532}{2}}$$

$$|V_{low-side}| = 0.9998\cancel{7}\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18)

$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\cancel{7}\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\cancel{88}\ kV$$

Apparent power (S):

Eq. (19)

$$S = P_{reported} + jQ$$

$$S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58\cancel{1383}.7\cancel{\angle 56.3}°$$

Example Calculations: Options 1b and 7b

Primary Impedance (Z_{pri}):

Eq. (20)
$$Z_{pri} = \frac{V_{bus}^2}{S^*}\cancel{\frac{V_{gen}^2}{S^*}}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle-58.7°\ MVA}\cancel{\frac{(21.88\ kV)^2}{1383.7\angle-56.3°\ MVA}}$$

$$Z_{pri} = 0.356\angle 58.7\cancel{3458\angle 56.3}°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7\cancel{3458\angle 56.3}°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}\cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 0.356\angle 58.7\cancel{3458\angle 56.3}°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7\cancel{6462\angle 56.3}°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1b and 7b:

Eq. (22)
$$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}\cancel{\frac{8.6462\angle 56.3°\ \Omega}{1.15}}$$

$$Z_{\sec limit} = 7.74\angle 58.7\cancel{5185\angle 56.3}°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (23)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\Omega}{\cos(85.0° - 58.7°)}\cancel{\frac{7.5185\Omega}{\cos(85.0° - 56.3°)}}$$

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}\cancel{\frac{7.5185\ \Omega}{0.8771}}$$

$$Z_{max} < 8.633\cancel{5715}\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

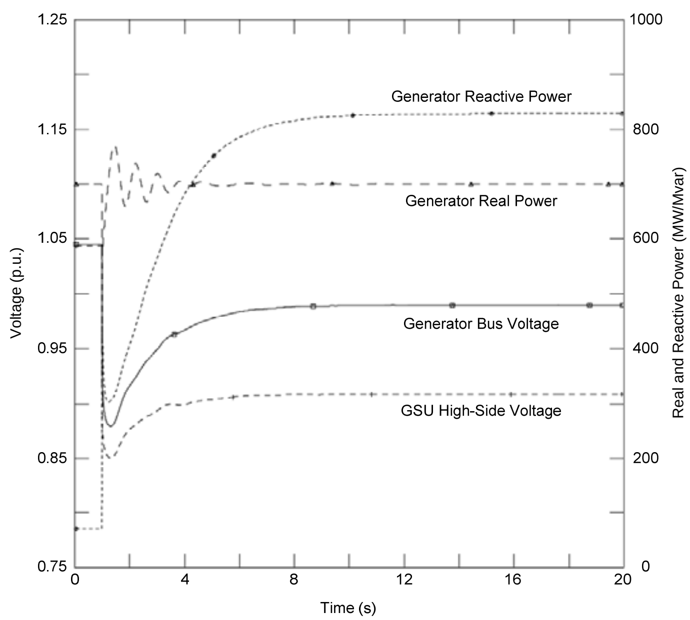
In this simulation the following values are derived:

$Q = 829.3$ Mvar

$V_{bus} = 0.990 = 21.78$ kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.~~



Apparent power (S):

Eq. (24) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j829.3\ Mvar$$

$$S = 1085.2\angle 49.8°$$

Example Calculations: Options 1c and 7c

Primary Impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.78\ kV)^2}{1085.2\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^\circ - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29~~24~~) $P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$

$P = 903\ MVA\ \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (30~~25~~) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31~~26~~) $V_{gen} = 0.95\ p.u.\ \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (32~~27~~) $S = P_{reported} + jQ$

$S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58\cancel{1383}.7\cancel{\angle 56.3}°\ MVA$

Primary current (I_{pri}):

Eq. (33~~28~~) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}\cancel{\frac{1383.7\ MVA}{1.73 \times 20.81\ kV}}$

$I_{pri} = 3738\cancel{38389.9}\ A$

Example Calculations: Option 2a

Secondary current (I_{sec}):

Eq. (~~3429~~) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\text{ A}}{\frac{25000}{5}} \cancel{\frac{38389.9\text{ A}}{\frac{25000}{5}}}$

$I_{sec} = 7.477\cancel{678}\text{ A}$

To satisfy the 115% margin in Option 2a:

Eq. (~~3530~~) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 7.477\cancel{678}\text{ A} \times 1.15$

$I_{\sec limit} > 8.59\cancel{883}\text{ A}$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (~~363 1~~) $P = GEN_{Synch\_namplate} \cancel{GEN_{namplate}} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (~~373 2~~) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

Eq. (38~~3~~3)
$$P_{pu} = \frac{P_{reported}}{MVA_{base}} \cancel{\frac{P}{MVA_{base}}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA} \cancel{\frac{767.6\ MW}{767.6\ MVA}}$$

$$P_{pu} = \cancel{1.}0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39~~3~~4)
$$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40~~3~~5)
$$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Use the formula below; calculate the low-side GSU~~generator step-up~~ transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat~~Repeat~~ the calculation as~~if~~ necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41~~3~~6)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right] \cancel{\frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}}$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right] \cancel{\frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}}$$

$$\cancel{\theta_{low-side} = \frac{5.92°}{0.8075}}$$

Example Calculations: Option 2b

$\theta_{low-side} = 6.7°$

~~.3°~~

Eq. (42~~3~~ ~~7~~)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \cancel{|V_{low-side}|} \cancel{= \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2} \cancel{\frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3}}{2}}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2} \cancel{\frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2} \cancel{\frac{0.8430 \pm 1.1532}{2}}$$

$$|V_{low-side}| = 0.999\cancel{8}1\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.999~~8~~1 per unit for the second iteration:

Eq. (43~~3~~ ~~8~~)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right] \cancel{\frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}}$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right] \cancel{\frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}}$$

$$\cancel{\theta_{low-side} = \frac{5.92°}{0.8484}}$$

$$\theta_{low-side} = 6.3\cancel{7.0}°$$

Eq. (44~~3~~ ~~9~~)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \cancel{|V_{low-side}|} \cancel{= \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2} \cancel{\frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0}}{2}}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2} \cancel{\frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2} \cancel{\frac{0.8437 \pm 1.1532}{2}}$$

$$|V_{low-side}| = 0.9998\cancel{7}\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (454~~0~~) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9998\cancel{7}\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\cancel{88}\ kV$$

Apparent power (S):

Eq. (464~~1~~) $S = P_{reported} + jQ$

$$S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58\cancel{1383}.7\cancel{\angle 56.3}°\ \text{MVA}$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (474 ~~2~~)
$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV} \cancel{\frac{1383.7\ MVA}{1.73 \times 21.88\ kV}}$$

$$I_{pri} = 35553 \cancel{36519.8}\ A$$

Secondary current (I_{sec}):

Eq. (484 ~~3~~)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ \text{A}}{\frac{25000}{5}} \cancel{\frac{36519.8\ \text{A}}{\frac{25000}{5}}}$$

$$I_{sec} = 7.111\cancel{304}\ \text{A}$$

To satisfy the 115% margin in Option 2b:

Eq. (494 4)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\cancel{304}\ \text{A} \times 1.15$$

$$I_{\sec limit} > 8.1784\ \text{A}$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

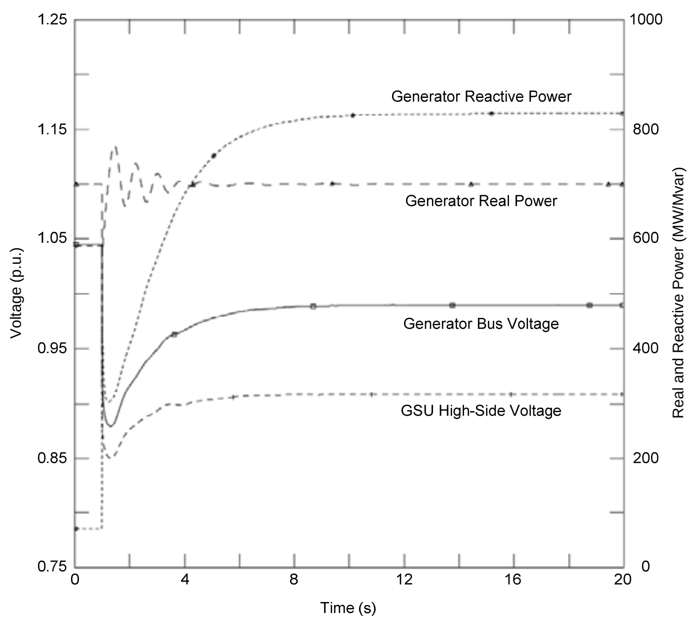
In this simulation the following values are derived:

$Q = 829.3$ Mvar

$V_{bus} = 0.990 = 21.78$ kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.~~



Apparent power (S):

Eq. (50) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j829.3\ Mvar$$

$$S = 1085.2\angle 49.8°$$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1085.2\ MVA}{1.73 \times 21.78\ kV}$$

$$I_{pri} = 28801\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28801\text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.760\text{ A}$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.760\text{ A} \times 1.15$$

$$I_{\sec limit} > 6.624\text{ A}$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

~~Real Power output (P):~~

~~Eq. (45)~~ $$\cancel{P = GEN_{namplate} \times pf}$$

$$\cancel{P = 903\ MVA \times 0.85}$$

$$\cancel{P = 767.6\ MW}$$

~~Reactive Power output (Q):~~

~~Eq. (46)~~ $$\cancel{Q = 150\% \times P}$$

$$\cancel{Q = 1.5 \times 767.6\ MW}$$

Example Calculations: Options 3 and 6

$~~Q = 1151.3\ Mvar~~$

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (5447) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (5548) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Options 4~~, 10,~~ and 10~~17~~

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. ~~Similarly, these calculations may also be applied to other asynchronous applications, including Option 17 for generator step-up transformers and lines that radially connect a generating plant to the Transmission system.~~ In this application it was assumed 20 Mvar~~100Mvar~~ of static compensation was added.

Real Power output (P):

Eq. (5649) $P = GEN_{Asych\_namplate} \cancel{GEN_{namplate}} \times pf$

$$P = 120\cancel{903}\ MVA \times 0.85$$

$$P = 102.0\cancel{767.6}\ MW$$

Reactive Power output (Q):

Eq. (5750) $Q = MVAR_{static} + GEN_{Async\_namplate} \cancel{GEN_{namplate}} \times \sin(\cos^{-1}(pf))$

$$Q = 20\cancel{100}\ Mvar + 63.2\ Mvar \cancel{\times 475.7\ Mva}$$

$$Q = 83.2\cancel{575.7}\ Mvar$$

Options 4~~, 10,~~ and 10~~17~~, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (5851) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

Example Calculations: Options 4~~, 10,~~ and 10~~17~~

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59~~52~~) $S = P + \cancel{P_{reported} +} jQ$

$$S = 102.0\cancel{767.6}\ MW + j83.2\cancel{j575.7}\ Mvar$$

$$S = 131.6\angle 39.2\cancel{959.5\angle 36.9}°\ MVA$$

$$\cancel{\theta_{transient\ load\ angle} = 36.9°}$$

Primary impedance (Z_{pri}):

Eq. (60~~53~~) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}\cancel{\frac{(21.9\ kV)^2}{959.5\angle -36.9°\ MVA}}$$

$$Z_{pri} = 3.644\ \angle 39.2\cancel{0.5001\angle 36.9}°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61~~54~~) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}\cancel{\frac{CT_{ratio}}{PT_{ratio}}}$

$$Z_{sec} = 3.644\ \angle 39.2°\cancel{0.5001\angle 36.9}\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}\cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 3.644\ \angle 39.2\cancel{0.5001\angle 36.9}°\ \Omega \times 5\cancel{25}$$

$$Z_{sec} = 18.22\ \angle 39.2\cancel{12.502\angle 36.9}°\ \Omega$$

To satisfy the 130% margin in Option 4~~1a~~:

Eq. (62~~55~~) $Z_{sec\,limit} = \frac{Z_{sec}}{130\%}$

$$Z_{sec\,limit} = \frac{18.22\angle 39.2°\ \ \Omega}{1.30}\cancel{\frac{12.502\angle 36.9°\ \Omega}{1.30}}$$

$$Z_{sec\,limit} = 14.02\angle 39.2\cancel{9.617\angle 36.9}°\ \Omega$$

Example Calculations: Options 4~~, 10,~~ and 10~~17~~

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (63~~56~~) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})} \cancel{Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)} \cancel{\frac{9.617\ \Omega}{\cos(85.0° - 36.9°)}}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972} \cancel{\frac{9.617\ \Omega}{0.6678}}$$

$$Z_{max} < 20.109 \cancel{14.401} \angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage restrained relay. In this application it was assumed 2~~1~~0~~0~~Mvar of static compensation was added.~~ Similarly, Option 6 uses the same calculation for asynchronous generators.~~

Real Power output (P):

Eq. (64~~57~~) $P = GEN_{Asynch\_namplate} \cancel{GEN_{namplate}} \times pf$

$$P = 120 \cancel{903}\ MVA \times 0.85$$

$$P = 102.0 \cancel{767.6}\ MW$$

Reactive Power output (Q):

Eq. (65~~58~~) $Q = MVAR_{static} + GEN_{Asynch\_namplate} \cancel{GEN_{namplate}} \times \sin(\cos^{-1}(pf))$

$$Q = 20 \cancel{100}\ Mvar + 63.24 \cancel{75.7}\ Mvar$$

$$Q = 83.25 \cancel{75.7}\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66~~59~~) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Example Calculations: Option 5

Apparent power (S):

Eq. (67~~60~~) $S = P + \cancel{P_{reported} +} jQ$

$S = 102.0\cancel{767.6}\ MW + j83.2\cancel{j575.7}\ Mvar$

$S = 131.6\angle 39.2\cancel{959.5\angle 36.9}°\ MVA$

Primary current (I_{pri}):

Eq. (68~~61~~) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}} \cancel{\frac{S}{\sqrt{3} \times V_{gen}}}$

$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV} \cancel{\frac{959.5\ MVA}{1.73 \times 21.9\ kV}}$

$I_{pri} = 3473\angle -39.2° \cancel{25295.3}\ A$

Secondary current (I_{sec}):

Eq. (69~~62~~) $I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}} \cancel{\frac{I_{pri}}{CT_{ratio}}}$

$I_{sec} = \frac{3473\angle -39.2°\ \text{A}}{\frac{5000}{5}} \cancel{\frac{25295.3\ \text{A}}{\frac{25000}{5}}}$

$I_{sec} = 3.473\angle -39.2° \cancel{5.06}\ \text{A}$

To satisfy the 130% margin in Option 5:

Eq. (70~~63~~) $I_{\sec limit} > I_{sec} \times 130\%$

$I_{\sec limit} > 3.473\angle -39.2° \cancel{5.06}\ \text{A} \times 1.30$

$I_{\sec limit} > 4.52\angle -39.2\cancel{6.58\angle -36.9}°\ A$

Example Calculations: Options 7a~~Option 8a, 8b, 9a, 9b, 15a,~~ and 10~~16~~a

This represents the calculation for a mixture of asynchronous and synchronous generation (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added.~~Option 8a represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to a synchronous generator. Similarly, these calculations can be applied to other synchronous generator applications, including Option 9a for generator step-up transformers applying a phase directional time overcurrent (67) directional toward the Transmission system relay, and Option 15a and 16a for lines that radially connect a generating plant to the Transmission system using a phase time overcurrent (51) and phase directional time overcurrent (67) directional toward the Transmission system relay, respectively. Options 8b and 9b use the same process, except the bus voltage is 0.85 per unit is used instead of 0.95 and excludes the generator step-up (GSU) impedance.~~

~~This example uses Option 8b as an example.~~

Synchronous Generation

Real Power output (P_{sync}):~~P):~~

Eq. (71) $$P_{sync} = GEN_{Synch\_nameplate} \times pf$$

$$P_{sync} = 903\ MVA \times 0.85$$

$$P_{sync} = 767.6\ MW$$

$$P_{sync-reported} = 700\ MW$$

Reactive Power Output (Q_{sync})

Eq. (72) $$Q_{sync} = 150\% \times P_{synch}$$

$$Q_{sync} = 150\% \times 767.6\ MW$$

$$Q_{sync} = 1151.3\ MW$$

Apparent Power (S_{sync})

Eq. (73) $$S_{sync} = P_{sync-reported} + jQ_{synch}$$

$$S_{sync} = 700MW + j1151.3\ MVAR$$

Asynchronous

Real Power output (P_{async}):

Eq. (74~~64~~) $$P_{async} = GEN_{Asynch\_namplate} \times pf \cancel{P = GEN_{namplate} \times pf}$$

$$P_{async} = 120\ MVA \times 0.85$$

$$P_{async} = 102.0\ MW$$

Example Calculations: Options 7a~~Option 8a, 8b, 9a, 9b, 15a,~~ and 10~~16a~~

Reactive Power output (Q_{async}):

Eq. (75) $$Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{async} = 20\ Mvar + 63.2\ Mvar$$

$$Q_{async} = 83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator bus voltage, however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (V_{gen}):

Eq. (76) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (77) $$S = 1.15 \times \left(P_{sync-reported} + jQ_{sync}\right) + 1.30 \times (P_{async} + jQ_{async})$$

$$S = 1.15 \times (700\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (78) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (79) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a~~Option 8a, 8b, 9a, 9b, 15a,~~ and 10~~16a~~

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 and the asynchronous apparent power has been multiplied by 1.30 in Equation 77 to satisfy the margin requirements in Options 7a and 10:

Eq. (80) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \ \ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \, \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (81) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \ \ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \ \ \Omega}{0.881}$$

$$Z_{max} < \ 7.17 \angle 85.0° \, \Omega$$

Example Calculations: Options 8a, 9a, 11, and 12

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of static compensation was added. The CTs are located on the low-side of the GSU.

Synchronous Generation

Real Power output (P_{sync}):

Eq. (82) $$P_{sync} = GEN_{Synch\_nameplate} \times pf$$

$$P_{sync} = 903 \ MVA \times .85$$

$$P_{sync} = 767.6 \ MW$$

$$P_{sync-reported} \ = 700 \ MW$$

Reactive Power Output (Q_{sync})

Eq. (83) $$Q_{sync} = 150\% \times P_{synch}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$Q_{sync} = 150\% \times 767.6\ MW$$

$$Q_{sync} = 1151.3\ Mvar$$

Apparent Power (S_{sync})

Eq. (84) $$S_{sync} = P_{sync-reported} + jQ_{synch}$$

$$S_{sync} = 700\ MW + j1151.3\ Mvar$$

$$S_{sync} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (85) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary Current ($I_{pri-sync}$):

Eq. (86) $$I_{pri-sync} = \frac{1.15 \times S^*_{sync}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ \mathrm{A}$$

Asynchronous

Real Power output (P_{async}):

Eq. (87) $$P_{async} = GEN_{Asynch\_namplate} \times pf$$

$$P_{async} = 120\ MVA\ \times 0.85$$

$$P_{async} = 102.0\ MW$$

Reactive Power output (Q_{async}):

Eq. (88) $$Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{async} = 20\ Mvar + 63.2\ Mvar$$

$$Q_{async} = 83.2\ Mvar$$

Example Calculations: Options 8a, 9a, 11, and 12

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (89) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{async}):

Eq. (90) $$S_{async} = 1.30 \times (P_{async} + jQ_{async})$$

$$S_{async} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{async} = 171.1\ \angle 39.2°\ MVA$$

Primary Current ($I_{pri-async}$):

Eq. (91) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{(171.1\ \angle -39.2°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ \mathrm{A}$$

Secondary current (I_{sec}):

Eq. (92) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\ \angle -58.7°\ \mathrm{A}}{\frac{25000}{5}} + \frac{4755 \angle -39.2°\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8°\ \mathrm{A}$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 in Equation 86 and the asynchronous has been multiplied by 1.30 in Equation 90.

Eq. (93) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8°\ \mathrm{A} \times 1.00$$

$$I_{\sec limit} > 9.514 \angle -56.8°\ A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

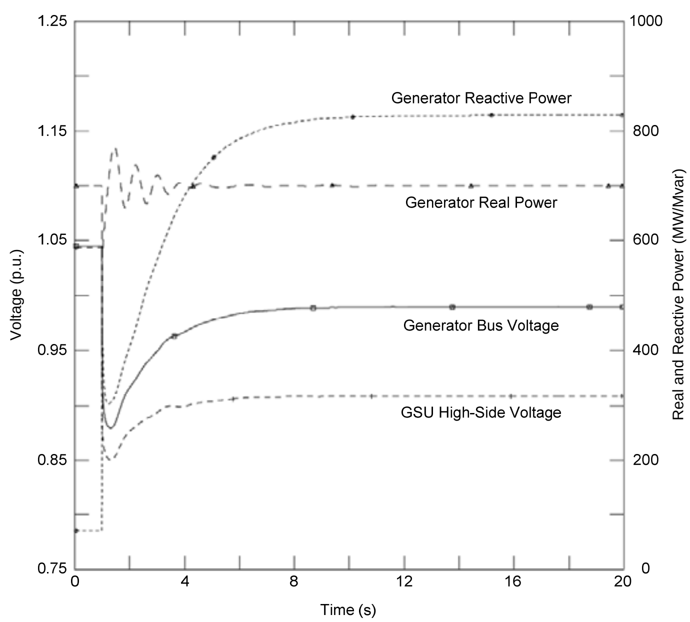
In this simulation the following values are derived:

$Q = 829.3$ Mvar

$V_{bus} = 0.990 = 21.78$ kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW



Apparent power (S):

Eq. (94) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j829.3\ Mvar$$

$$S = 1085.2\angle 49.8°$$

Example Calculations: Options 8c and 9c

Primary current (I_{pri}):

Eq. (95) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1085.2\ MVA}{1.73 \times 21.78\ kV}$$

$$I_{pri} = 28801\ A$$

Secondary current (I_{sec}):

Eq. (96) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28801\ \mathrm{A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.760\ \mathrm{A}$$

To satisfy the 115% margin in Option 8c:

Eq. (97) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 5.760\ \mathrm{A} \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 6.624\ \mathrm{A}$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added.

Real Power output (P):

Eq. (98) $$P = GEN_{Asynch\_namplate} \times pf$$

$$P = 120\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (99) $$Q = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 20\ Mvar + 63.2\ Mvar$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (100) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (101) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (102) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (103) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (104) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization.

Primary current (I_{pri}):

Eq. (105) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (106) $$I_{sec} = \frac{I_{pri}}{CT_{uat}}$$

$$I_{sec} = \frac{2510.2\text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

To satisfy the 150% margin in Option 13a:

Eq. (107) $$I_{\text{sec}\,limit} > I_{sec} \times 150\%$$

$$I_{\text{sec}\,limit} > 2.51\text{ A} \times 1.50$$

$$I_{\text{sec}\,limit} > 3.77\text{ A}$$

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

Real Power output (P):

Eq. (108) $$P = GEN_{Synch\_namplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 14a

Reactive Power output (Q):

Eq. (109~~65~~) $Q = 120\cancel{150}\% \times P$

$$Q = 1.2\cancel{5} \times 767.6\ MW$$

$$Q = 921.1\cancel{1151.3}\ Mvar$$

Option 14a~~8b~~, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):~~:~~

Eq. (110~~66~~) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (111~~67~~) $S = P_{reported} + jQ$

$$S = 700.0\cancel{767.6}\ MW + j921.1\cancel{j1151.3}\ Mvar$$

$$S = 1157.0\angle 52.77\cancel{1383.7\angle 56.3}°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}~~current (I_{pri}~~):

Eq. (112~~68~~) $Z_{pri} = \frac{V_{bus}^2}{S^*}\cancel{I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}}$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}\cancel{I_{pri} = \frac{1383.7\ MVA}{1.73 \times 293.25\ kV}}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega\cancel{I_{pri} = 2724.3\ A}$$

Secondary impedance (Z_{sec}~~current (I_{sec}~~):

Eq. (113~~69~~) $Z_{sec} = Z_{pri} \times \frac{CT_{hv}}{PT_{hv}}\cancel{I_{sec} = \frac{I_{pri}}{CT_{ratio}}}$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}\cancel{I_{sec} = \frac{2724.3\ A}{\frac{25000}{5}}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2\cancel{I_{sec} = 0.545\ A}$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

~~Example Calculations: Option 14a~~

To satisfy the 115% margin in Option 14a~~8a~~:

Eq. (114~~70~~) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$ ~~$I_{\sec limit} > I_{sec} \times 115\%$~~

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (115) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{12.928\Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

~~$I_{\sec limit} > 0.545\ A \times 1.15$~~

~~$I_{\sec limit} > 0.627\ A$~~

Example Calculations: Option~~Options 7c, 8c, 9c~~ 14b~~, 15b, and 16b~~

Option 14b represents the simulation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

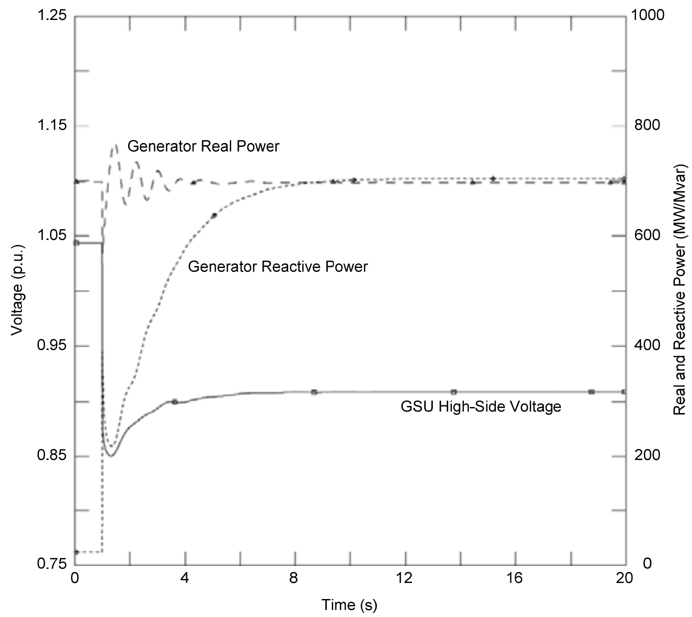
$Q = 704.4$ Mvar

$V_{bus} = 0.908 = 313.3$ kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~These options require simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.~~

Example Calculations: ~~OptionOptions 7c, 8c, 9c~~ 14b~~, 15b, and 16b~~



Apparent power (S):

Eq. (116) $S = P_{reported} + jQ$

$$S = 700.0\ MW + j704.4\ Mvar$$

$$S = 993.1\angle 45.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.2°$$

Primary impedance (Z_{pri}):

Eq. (117) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(313.3\ kV)^2}{993.1\angle -45.2°\ MVA}$$

$$Z_{pri} = 98.84\angle 45.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (118) $Z_{sec} = Z_{pri} \times \frac{CT_{hv}}{PT_{hv}}$

$$Z_{sec} = 98.84\angle 45.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.84\angle 45.2°\ \Omega \times 0.2$$

Example Calculations: ~~Option~~~~Options 7c, 8c, 9c~~ 14b~~, 15b, and 16b~~

$$Z_{sec} = 19.77\angle 45.2°\,\Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (119) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.77\angle 45.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.19\angle 45.2°\,\Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (120) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.19\,\Omega}{\cos(85.0° - 45.2°)}$$

$$Z_{max} < \frac{17.19\,\Omega}{0.768}$$

$$Z_{max} < 22.38\angle 85.0°\,\Omega$$

Example Calculations: Options 15a~~11a~~ and 16a~~12~~

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU. ~~Option 11 represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 100Mvar of static compensation was added.~~

Real Power output (P):

Eq. (121~~71~~) $$P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (122~~72~~) $$Q = 120\% \times P\cancel{Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q = 1.2 \times 767.6\ MW\cancel{Q = 100\ Mvar + 475.7\ Mvar}$$

Example Calculations: Options 15a~~11a~~ and 16a~~12~~

$$Q = 921.12\cancel{575.7}\ Mvar$$

Option 15a~~Options 11 and 12~~, Table 1 – Bus Voltage, calls for a ~~1.~~0.85 per unit of the high-side nominal voltage:~~ for the generator bus voltage (V_{gen}):~~

Eq. (123~~73~~) $$V_{bus} = \cancel{V_{gen} = 1.}0.85\ p.u. \times V_{nom} \cancel{\times GSU_{ratio}}$$

$$V_{bus} = \cancel{V_{gen} = 1.}0.85 \times 345\ kV \cancel{\times \left(\frac{22\ kV}{346.5\ kV}\right)}$$

$$V_{bus} = 293.25 \cancel{V_{gen} = 21.9}\ kV$$

Apparent power (S):

Eq. (124~~74~~) $$S = P_{reported} + jQ$$

$$S = 700\cancel{767.6}\ MW + j921.12\cancel{j575.7}\ Mvar$$

$$S = 1157\angle 52.8\cancel{959.5\angle 36.9}°\ MVA$$

Primary current (I_{pri}):

Eq. (125~~75~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}} \cancel{\frac{S}{\sqrt{3} \times V_{gen}}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ \text{MVA}}{1.73 \times 293.25\ kV} \cancel{\frac{959.5\ MVA}{1.73 \times 21.9\ kV}}$$

$$I_{pri} = 2280.6\angle -52.8° \cancel{25295}\ A$$

Secondary current (I_{sec}):

Eq. (126~~76~~) $$I_{sec} = \frac{I_{pri}}{CT_{hv}} \cancel{\frac{I_{pri}}{CT_{ratio}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ \text{A}}{\frac{2000}{5}} \cancel{\frac{25295\ A}{\frac{25000}{5}}}$$

$$I_{sec} = 5.701\angle -52.8° \cancel{059}\ \text{A}$$

To satisfy the 115~~130~~% margin in Option 15a~~Options 11 and12~~:

Eq. (127~~77~~) $$I_{sec\,limit} > I_{sec} \times 115\cancel{130}\%$$

$$I_{sec\,limit} > 5.701\angle -52.8° \cancel{059}\ \text{A} \times 1.15\cancel{30}$$

$$I_{sec\,limit} > 6.56\angle -52.8° \cancel{575}\ \text{A}$$

Example Calculations: Options 15b~~Option 13a~~ and 16b~~13b~~

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

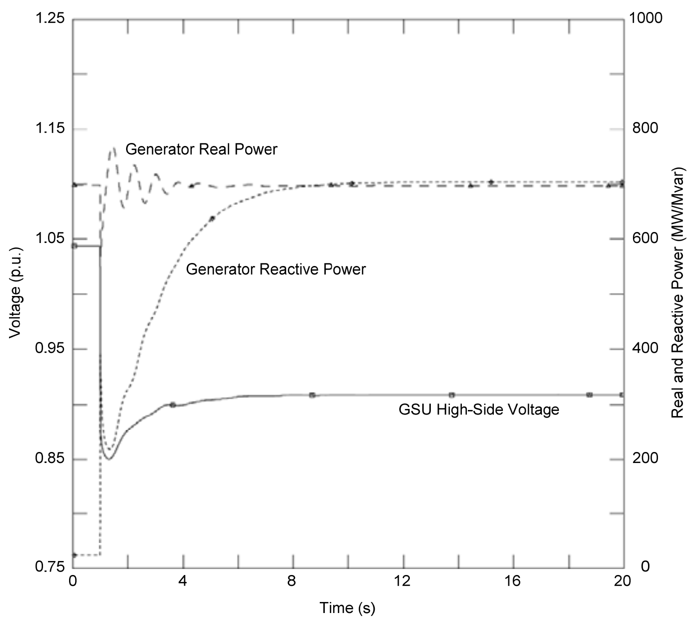
In this simulation the following values are derived:

$Q = 704.4$ Mvar

$V_{bus} = 0.908 = 313.3$ kV

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.~~



Apparent power (S):

Eq. (128) $S = P_{reported} + jQ$

$$S = 700\ MW + j704.4\ Mvar$$

$$S = 993.1\angle 45.2°\ MVA$$

Example Calculations: Options 15b~~Option 13a~~ and 16b~~13b~~

Primary current (I_{pri}):

Eq. (129~~78~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}} \cancel{\frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}}$$

$$I_{pri} = \frac{993.1\angle -45.2° \text{ MVA}}{1.73 \times 313.3\ kV} \cancel{\frac{60\ MVA}{1.73 \times 13.8\ kV}}$$

$$I_{pri} = 1832\cancel{2510}.2\angle -45.2°\ A$$

Secondary current (I_{sec}):

Eq. (130~~79~~) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}} \cancel{\frac{I_{pri}}{CT_{uat}}}$$

$$I_{sec} = \frac{1832.2\angle -45.2° \text{ A}}{\frac{2000}{5}} \cancel{\frac{2510.2 \text{ A}}{\frac{5000}{5}}}$$

$$I_{sec} = 4.580\angle -45.2°\cancel{.51} \text{ A}$$

To satisfy the 115~~150~~% margin in Option 15b~~13a~~:

Eq. (131~~80~~) $$I_{\sec limit} > I_{sec} \times 115\cancel{150}\%$$

$$I_{\sec limit} > 4.580\angle -45.2° \times 1.15$$

$$I_{\sec limit} > 5.267\angle -45.2° \text{ A}$$

Example Calculations: Option 17

Option 17 represents the calculation for an asynchronous generation interconnection facility applying a phase distance (21) - directional toward the Transmission. In this application it was assumed 20 Mvar of static compensation was added.

$$\cancel{I_{\sec limit} > 2.51 \text{ A} \times 1.50}$$

$$\cancel{I_{\sec limit} > 3.77 \text{ A}}$$

~~Example Calculations: Option 14a~~

~~Option 14a represents the calculation for lines that radially connect an asynchronous generating plant to the Transmission system for a phase directional time overcurrent (67) directional toward the Transmission system relay.~~

Real Power output (P):

Eq. (132~~81~~) $P_{async} = GEN_{Asynch\_namplate} \times pf \cancel{P = GEN_{namplate} \times pf}$

$P_{async} = 120 \cancel{P = 903}\ MVA \times 0.85$

$P_{async} = 102.0 \cancel{P = 767.6}\ MW$

Reactive Power output (Q):

Eq. (133~~82~~) $Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf)) \cancel{Q = 150\% \times P}$

$\cancel{Q = 1.5 \times 767.6\ MW}$

$Q_{async} = 20\ Mvar + 63.2 \cancel{Q = 1151.3}\ Mvar$

$Q_{async} = 83.2\ Mvar$

Option 17~~14a~~, Table 1 – Bus Voltage, calls for a 1.00~~0.85~~ per unit of the high-side nominal voltage for the bus~~generator step-up (GSU)~~ voltage (V_{bus}~~V_{nom}~~):

Eq. (134~~83~~) $V_{bus} = 1.00 \cancel{0.85}\ p.u. \times V_{nom}$

$V_{gen} = 1.00 \cancel{0.85} \times 345\ kV$

$V_{gen} = 345.0 \cancel{293.25}\ kV$

Apparent power (S):

Eq. (135~~84~~) $S = P + \cancel{P_{reported} +} jQ$

$S = 102.0 \cancel{767.6}\ MW + j83.2 \cancel{j1151.3}\ Mvar$

$S = 131.6\angle 39.2 \cancel{1383.7\angle 56.3}°\ MVA$

$\cancel{\theta_{transient\ load\ angle} = 56.3°}$

Primary impedance (Z_{pri}):

Eq. (136~~85~~) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA} \cancel{\frac{(293.25\ kV)^2}{1383.7\angle -56.3°\ MVA}}$$

$Z_{pri} = 904.4\angle 39.2 \cancel{62.1481\angle 56.3}°\ \Omega$

~~Example Calculations: Option 14a~~

Secondary impedance (Z_{sec}):

Eq. (~~86~~137) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}} \cancel{\frac{CT_{ratio}}{PT_{ratio}}}$$

$$Z_{sec} = 904.4\angle 39.2 \cancel{62.1481\angle 56.3}° \, \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}} \cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 904.4\angle 39.2° \cancel{62.1481\angle 56.3°} \, \Omega \times 0.03\cancel{25}$$

$$Z_{sec} = 27.13\angle 39.2\cancel{1553.7\angle 56.3}° \, \Omega$$

To satisfy the 130~~115~~% margin in Option 17~~14a~~:

Eq. (138~~87~~) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%} \cancel{\frac{Z_{sec}}{115\%}}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2° \ \Omega}{1.30} \cancel{\frac{1553.7\angle 56.3° \, \Omega}{1.15}}$$

$$Z_{\sec limit} = 20.869\angle 39.2\cancel{1351.0\angle 56.3}° \, \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (139~~88~~) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869 \, \Omega}{\cos(85.0° - 39.2°)} \cancel{\frac{1351.0 \, \Omega}{\cos(85.0° - 56.3°)}}$$

$$Z_{max} < \frac{20.869 \, \Omega}{0.697} \cancel{\frac{1651.0 \, \Omega}{0.8771}}$$

$$Z_{max} < 29.941\cancel{1540.3}\angle 85.0° \, \Omega$$

Example Calculations: Options ~~11b,~~ 18~~,~~ and 19

Option 18~~11b~~ represents the calculation for a generation interconnection Facility~~generator step-up (GSU) transformer~~ applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 19~~18~~ may also be applied here~~ as well for generation interconnection Facilities and Option 19~~ for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 20~~100~~ Mvar of static compensation was added.

Real Power output (P):

Eq. (140~~89~~) $$P = GEN_{Asych\_namplate} \cancel{GEN_{namplate}} \times pf$$

Example Calculations: Options ~~11b,~~ 18~~,~~ and 19

$$P = 120\cancel{903}\ MVA \times 0.85$$

$$P = 102.0\cancel{767.6}\ MW$$

Reactive Power output (Q):

Eq. (141~~90~~) $$Q = MVAR_{static} + GEN_{Asych\_namplate}\cancel{GEN_{namplate}} \times \sin(\cos^{-1}(pf))$$

$$Q = 20\cancel{100}\ Mvar + 63.24\cancel{75.7}\ Mvar$$

$$Q = 83.25\cancel{75.7}\ Mvar$$

Options ~~11b,~~ 18~~,~~ and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}~~for the generator bus voltage (V_{gen}~~):

Eq. (142~~91~~) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus}\cancel{V_{gen}} = 1.0 \times 345\ kV$$

$$V_{bus}\cancel{V_{gen}} = 345\ kV$$

Apparent power (S):

Eq. (143~~92~~) $$S = P + \cancel{P_{reported} +} jQ$$

$$S = 102.0\cancel{767.6}\ MW + j83.2\cancel{j575.7}\ Mvar$$

$$S = 131.6\angle 39.2\cancel{959.5\angle 36.9}°\ MVA$$

Primary current (I_{pri}):

Eq. (144~~93~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}\cancel{\frac{S}{\sqrt{3} \times V_{gen}}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}\cancel{\frac{959.5\ MVA}{1.73 \times 345\ kV}}$$

$$I_{pri} = 220.5\angle -39.2°\cancel{1605}\ A$$

Secondary current (I_{sec}):

Eq. (145~~94~~) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}\cancel{\frac{I_{pri}}{CT_{HV}}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}\cancel{\frac{1605\ A}{\frac{2000}{5}}}$$

$$I_{sec} = 3.675\angle -39.2°\cancel{4.014}\ A$$

Example Calculations: Options ~~11b,~~ 18~~,~~ and 19

To satisfy the 130% margin in Options ~~11b,~~ 18~~,~~ and 19:

Eq. (146~~95~~) $I_{\sec limit} > I_{sec} \times 130\%$

$I_{\sec limit} > 3.675\angle -39.2° \cancel{4.014}\ \text{A} \times 1.30$

$I_{\sec limit} > 4.778\angle -39.2° \cancel{5.218}\ \text{A}$

End of calculations

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Relay Loadability: Generator.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF. Draft PRC-023-3 Requirement R7 and R8 replace Criterion 6 and also have a VRF of High. Requirements R7 and R8 establish identical criteria as established within PRC-025-1 for generator interconnection Facilities and generator step-up (GSU) transformers.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on "pass-fail" or a binary condition. The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on “an applied load-responsive protective relay” in accordance with Attachment 1: Relay Settings.

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Relay Loadability: Generator.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF. Draft PRC-023-3 Requirement R7 and R8 replace Criterion 6 and also have a VRF of High. Requirements R7 and R8 establish identical criteria as established within PRC-025-1 for generator interconnection Facilities and generator step-up (GSU) transformers.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on “an applied load-responsive protective relay” in accordance with Attachment 1: Relay Settings.

Project 2010-13.2 Generator Relay Loadability

Consideration of Issues and Directives

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
NERC Ref: S-10724 Para 106 supported by Paragraphs 104, 105, and 108. **106.** We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability. Para 104, 105, and 108 **104.** We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC-023-1 to address	Order No. 733 (Para 104, 105, 106, and 108)	**Response to P106** The Reliability Standard PRC-025-1 is responsive to paragraph 106 by establishing a new standard that addresses generator unit relay loadability for load-responsive protective relays applicable to generators for the conditions (depressed voltages) observed during the August 2003 blackout in the northeastern portion of North America. **Response to P104** The Reliability Standard PRC-025-1 is responsive to paragraph 104 by establishing requirements for load-responsive protective relays on generator step-up (GSU) transformers and on unit auxiliary transformers (UAT) that supply station service power to support the on-line

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC-023-1. **105.** In light of the EROs statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a		operation of generating plants. These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. The standard is coordinated with the expected outcomes of PRC-023-2 in that it will assure that the applicable equipment will not be removed from service unnecessarily for the conditions observed during the August 2003 blackout in the northeastern portion of North America. **Response to P105** The Reliability Standard PRC-025-1 is responsive to paragraph 105 by developing a new standard to address generator relay loadability according to the filed schedule. This Phase II of relay loadability required an extension of time to complete, extending the deadline to September 30, 2013. A one year extension was granted on February 15, 2012, Docket No. RM08-13-001. **Response to P108** The Reliability Standard PRC-025-1 is responsive to

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA. **108.** Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.		paragraph 108 by establishing a requirement for each Generator Owner to apply settings on its load-responsive protective relays for generator step-up (GSU) transformers. For GSU transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO); and 150% of the unit's Reactive Power capability, in megavoltampere-reactive (Mvar) derived from the nameplate megavoltampere (MVA) rating at rated power factor. For GSU transformers connected to asynchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the aggregated generators at rated power factor. Asynchronous

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator criteria also include inverter-based installations.

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3 and PRC-025-1

Successive Ballot and Non-Binding Poll now open for PRC-025-1 through May 24, 2013

Now Available

A successive ballot of **PRC-025-1** – Generator Relay Loadability and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now being conducted through **8 p.m. Eastern on Friday, May 24, 2013**.

PRC-023-3 – Transmission Relay Loadability is currently posted for a 30-day formal comment period.

Background information for this project can be found on the project page.

Instructions

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results for **PRC-025-1** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation
PRC-023-3 & PRC-025-1

Formal Comment Period for PRC-025-1 and PRC-023-3: April 25, 2013 – May 24, 2013

Upcoming:
Successive Ballot and Non-Binding Poll for PRC-025-1: May 15, 2013 – May 24, 2013

Now Available

A 30-day formal comment period is open for **PRC-023-3** – Transmission Relay Loadability and **PRC-025-1** – Generator Relay Loadability through **8 p.m. Eastern on Friday, May 24, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-023-3** and **PRC-025-1** is open through **8 p.m. Eastern on Friday, May 24, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A successive ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will be conducted from May 15, 2013 through May 24, 2013.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation
PRC-025-1

Successive Ballot and Non-binding Poll Results

Now Available

A successive ballot of **PRC-025-1** – Generator Relay Loadability and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Friday, May 24, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the successive ballot.

Approval	Non-binding Poll Results
Quorum: 81.25% Approval: 69.23%	Quorum: 80.17% Supportive Opinions: 61.11%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Reliability Standards Analyst, at monica.benson@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Successive Ballot 2013_sc_1
Ballot Period:	5/15/2013 - 5/24/2013
Ballot Type:	Successive
Total # Votes:	299
Total Ballot Pool:	368
Quorum:	**81.25 % The Quorum has been reached**
Weighted Segment Vote:	69.23 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	98	1	44	0.677	21	0.323	12	21
2 - Segment 2.	10	0.7	6	0.6	1	0.1	2	1
3 - Segment 3.	81	1	38	0.613	24	0.387	5	14
4 - Segment 4.	28	1	13	0.619	8	0.381	3	4
5 - Segment 5.	80	1	33	0.532	29	0.468	6	12
6 - Segment 6.	54	1	28	0.667	14	0.333	0	12
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.3	3	0.3	0	0	0	4
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1
10 - Segment 10.	7	0.6	5	0.5	1	0.1	1	0
Totals	**368**	**6.8**	**172**	**4.708**	**98**	**2.092**	**29**	**69**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Abstain	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer		
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	

1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	

4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Michael Shultz	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Negative	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson		
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart		
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Colorado Springs	Shannon Fair	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Affirmative	

6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Legal and Privacy
404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Non-binding Poll Results

Project 2010-13.2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Non-binding
Poll Period:	5/15/2013 - 5/24/2013
Total # Opinions:	275
Total Ballot Pool:	343
Summary Results:	80.17% of those who registered to participate provided an opinion or an abstention; 61.11% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Abstain	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer		
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	

1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	

1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		

3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	

3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	

5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Michael Shultz	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	

NERC

5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Colorado Springs	Shannon Fair	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts	Donald Nelson	Affirmative	

	Department of Public Utilities			
9	Gainesville Regional Utilities	Norman Harryhill		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Name (31 Responses)
Organization (31 Responses)
Group Name (50 Responses)
Lead Contact (50 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (9 Responses)
Comments (50 Responses)
Question 1 (37 Responses)
Question 1 Comments (50 Responses)
Question 2 (33 Responses)
Question 2 Comments (50 Responses)
Question 3 (33 Responses)
Question 3 Comments (50 Responses)
Question 4 (32 Responses)
Question 4 Comments (50 Responses)
Question 5 (39 Responses)
Question 5 Comments (50 Responses)

Texas Reliability Entity
Texas Reliability Entity
NA
NA
No
(1) Texas RE objects to the use of the term Regional Reliability Organization (RRO) in Table 1. RRO is an obsolete term that NERC had been trying to purge from the standards, and we are somewhat alarmed to see it used in a new place in the standards. While we recognize that RRO is defined in the Glossary, it is not in the functional model and, at least in our region, it does not identify any entity and it is ambiguous. We urge you to replace the term RRO with an entity type from the functional model, or to write a description of what is intended without using the term "RRO". (2) Regarding the “Transformers” section on page 7 and footnote 3 on page 10, consider whether it is appropriate to use the “nameplate impedance at the nominal GSU turns ratio” in all instances. In some cases, it is more appropriate to use the calculated (i.e. with compensation) impedance that reflects the lowest value based on the de-energized tap and LTC tap positions for this purpose. (3) For Options 1a, 2a, and 7a, consider using 0.9 per unit instead of 0.95 per unit, because typical disturbance (post-contingency) voltage criterion is 0.9 p.u. (4) Consider clarifying that the Real Power output criteria should be based on the [highest seasonal] MW rating for the applicable unit. There can be significant seasonal variations in MW capabilities for some units. We don’t expect pickup settings to be changed from season to season, so an appropriate year-round setting should be determined and applied. (5) Some transmission systems have steady state stability limits that encroach into the generator capability limits. Consider adding exclusion criteria for these types of scenarios.
Texas RE generally supports this standard as written, other than the use of the term *Regional Reliability Organization* in Table 1 as described above. Our other comments are provided for consideration by the drafting team.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes

Yes
Yes
Yes
2) We suggest removing Section 3.2.3 and footnote 1. UAT protection is part of the station service system and should not be in this standard. Remove the UAT from Table 1. The UAT relays are not in the category of “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” The highside overcurrent pickup should not be required to be at 150%. Settings at > & = 115% should be allowed. 3) We believe that the Purpose statement should end "… do not pose a risk of damaging the generator." 4) The protection of the generator should be the paramount concern. All ANSI standards for generator and main power transformer protection should be considered to be the ruling guide for protecting the equipment. The minimum allowable settings provided in the table in the draft standard do not factor using time delays in order to provide adequate protection for generators. 5) The overload relay that protects the generator from overload may also be the relay that protects the GSU from overload. In the exception list of the draft standard, exception bullet #5 should take precedence over exception bullet #6. 6) The protection requirements (exception bullet #5) from the ANSI standards need additional recognition, development, and emphasis in the Exceptions section. As written, it appears to be an afterthought. The ANSI standard for synchronous generator protection should be recognized, respected, and not violated. The Table 1 setting specifications which contradict the ANSI standards should be submissive to the ANSI standards and itemized in the exception criteria. Consider removing “extremely” from the "extremely inverse time" description as various vendors call the varying inverse time curve by different names. 7) The generator overload protection exception added to Draft 3 for extremely inverse characteristics (fifth exception bullet) is an improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, the value determined from the generator nameplate MVA at rated voltage, or is it the base or top (no fans, no oil circulation) MVA rating of the GSU? 8) The wording in the sixth exception bullet of the Exceptions section is too vague. How much of an overload is considered an overload? Many vendor relay curves do not provide characteristics showing the value of current that will time out in 15 minutes. It may be difficult to prove a setting to provide 15 minute delay. Existing relays in service do not have the ability to be set by this criterion. 9) The Exceptions section seems to state that the exceptions are allowed only during start up and when off line, which is unacceptable. The exceptions should be allowed at all times. 10) To meet the requirements of table 1 for non-51 relays (distance relays set at approximately 180% of generator MVA) and meet our protection philosopy objectives, we would have to install many new relays for overload protection. 11) Determination of the pickup of the distance relays is too complicated. The calculated impedance should be based on generator nameplate MVA and pf only. The requirements make what should be a simple calculation based on generator electrical characteristics into one that will require the relay engineer to find test MW data is not readily unavailable. 12) PRC-025 should be revised to "grandfather" existing protection settings that have been proven in practice for many decades not to prematurely remove equipment from service. 13) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, whose tripping would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings for retoration purposes. 14) Voltage-restrained overcurrent relays are notorious for not having a predictable operation time under fault conditions. If they are included in the types of equipment that mis-operated in the August 2003 blackout, they should be required to be replaced with another relay type rather than requiring that the settings be relaxed to the degree specified in the draft standard. 15) A High VRF and a Severe VSL seems overly harsh given the compliance feasibility uncertainties. 16) Which UATs are proposed to be included, if any, is confusing. Suggest adding diagrams to the reference document. 17) During the webinar there were three slides related to the different trans to Gen interconnections and who is responsible for what; suggest adding and or clarifying these in the reference documents.
Vladimir Stanisic
AESI Inc.
na

na
Yes
No
The team is commended for an extensive effort to provide high level of detail through numerous relay setting examples summarized in Table 1 and elaborated in the document PRC_025_1_Guidlines_and_Technical_Basis_Draft_3_2013_04_24_Redline.pdf. Nonetheless, the following points may need further attention: 1. The settings derived by simulations versus the settings derived by manual calculations are noticeably different, the latter being repeatedly much more conservative (e.g. 8c: 6.6 A pu versus 8a: 9.5 A pu), exposing generators to a higher risk of overloading. It would be expected that the results of manual calculations and simulations would yield closer values, at least for most of typical configurations. It appears that underlying assumptions used in the calculations and simulations may need to be fine-tuned. For example, is it realistic to have field forcing producing 1.5 pu MVAR output and at the same time generator bus voltage at 0.95 pu. 2. The settings derived by manual calculations are such the generators are exposed to a higher risk of overloading: • Example 1a – 21 protection would operate only when unit loading exceeds approx. 280% (at rated power factor). • Example 2a – 51V protection pickup is set at equivalent of approx. 170% loading. Taking into account that overcurrent relays actually react when current exceeds 1.5 pickup setting, equivalent loading on the unit would have to exceed 250% before timing is initiated. Depending on the relay characteristic, time delay can be significant. 3. C37.102 states that acceptable settings for 21 function are 150% to 200% (at rated power factor). These values should guide the requirements of this standard. 4. The Table specifies pickup setting criteria. It remains unclear when are the relays allowed to trip. 5. Examples 7a, b, c, seem to be duplication of 1a, b, c. 6. The following comment from the Guidelines document is not clear: ====== Options 7a and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator bus voltage, ***however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (Vgen)***?: ==========
No
Please see comments on Question 2.
Yes
Yes
This draft of the standard uses 0.85 pu transmission system voltage as a benchmark for determining the settings. The latest version of PRC-024-1 defines post-disturbance voltage profile where the system voltage is below 0.85 pu up to 3 seconds. Is there a need to take that into consideration for this standard.
Northeast Power Coordinating Council
Guy Zito
Yes
In PRC-023-3, add “Each” to the beginning of R8.
Pepco Holdings Inc. & Afffiliates
David Thorne
No
1) The inclusion of Requirements R7 and R8 and the entire Table 1 from PRC-025-1 overly complicates PRC-023-3. In addition, inclusion of these Table 1 requirements without the corresponding Guidelines and Technical Basis document produced for PRC-025 makes the application

of Table 1 in PRC-023 difficult, if not impossible. The intent of the original PRC-023 was to apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. The new PRC-025 standard should apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES generators, GSUs, UAT's and Generator Interconnection Facilities. In a good faith effort to provide a bright line between the two standards, the new PRC-023-3 standard became overly complicated and extremely confusing. It would seem that instead of adding PRC-025 requirements to PRC-023, it would be much simpler to just add Transmission Owners to the Applicability Entities section of PRC-025. The Applicable Facilities section of each standard should identify that any load responsive relay (whether they are owned by GO's or TO's) installed on these types of facilities must comply with the respective requirements of that standard. If this were done then the original PRC-023 could be revised to exclude relays installed on generators, GSU's, UAT's and Generator Interconnection Facilities, as they will be covered by PRC-025. PRC-023 would apply solely to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. 2) It is unnecessary to remove Criterion 6 from PRC-023-3 as it represents an acceptable alternative to the methods offered in PRC-025. When load responsive relays are set on transmission line terminals connected to generation stations remote from load in accordance with Criterion 6 of PRC-023 (230% of aggregate generation nameplate capability) the resulting setting provides sufficient margin to accommodate acceptable loadability. This criterion has been successfully used for years and has gone through the full standards development process and been vetted as an acceptable alternative. Consider the example calculation for Option 14a in PRC-025. From Equation 112 the apparent primary impedance seen by the relay on the high side of the GSU is 74.3 ohms primary at an angle of 52.77 degrees. Now assume the 230% method from PRC-023 Criterion 6 was used instead. The new apparent power would be 2.3 x (767.6 MW + j 475.6 MVAR) = 2.3 x 903 MVA =2076.9 MVA at an angle of 31.8 degrees. Using Equation 112 the apparent primary impedance would be 41.4 ohms at 31.8 degrees. From Equation 115 the setting required to satisfy Option 14a criteria from PRC-025 would be 15.283 ohms sec = 76.42 ohms primary at 85 degrees. The reach of this relay along the 31.8 degree load angle would be 76.42 x Cos (85 – 31.8) = 45.77 ohms primary. Since this is greater than the 41.4 ohm setting resulting from Criterion 6 of PRC-023, the PRC-023 Criterion is slightly more conservative, requiring a slightly smaller relay reach than Option 14a. As such, both methods should be considered equally effective in ensuring relay loadability.
No
For the PRC-025 standard the inclusion of Table 1 along with the Figures and Example Calculations in the Guidelines and Technical Basis document clearly identifies the proposed setting criteria. However, the inclusion of Table 1 in PRC-023 overly complicates the scope of PRC-023, and without inclusion of the corresponding Guidelines and Technical Basis document makes application of Table 1 criteria difficult. We feel strongly that all references to load responsive relays applied on generators, GSU's, UAT's and Generation Interconnection Facilities (including Table 1 and Requirements R7 and R8) should be eliminated from PRC-023 as they are already adequately covered in PRC-025. Transmission Owners that own load responsive relays on those types of facilities should be included as an Applicable Entity under PRC-025. (See comments submitted for Question 1).
No
1) The new term "Generator Interconnection Facilities" is not defined in the NERC Glossary of terms, nor is it defined in the body of the standard. It is defined in the Guidelines and Technical Basis document; however, we feel this term needs to be defined within the body of the standard itself. Perhaps a footnote similar to that used to define Unit Auxiliary Transformers would be appropriate. We would suggest the same definition used in the Guidelines and Technical Basis document be inserted: "Generator interconnection Facility(ies) consists of Elements between the generator step-up transformer and the interface with the portion of the bulk Electric System (BES) where Transmission Owners take over the ownership." 2) In Figures 4 and 5 the CT's supplying the 21, 51V-R and 51V-C relays connected to the generator(s) look like they are connected to the generator neutral. To make it clear that they are supplied from CT's connected in the phase leads, a phase to neutral transition symbol (ref Fig 7.4 in IEEE C37.102) should be used to indicate the CTs are located above the neutral connection point. 3) In Figure 5 there is a 51 relay shown connected to the 22kV bus leads supplying the generator on the left hand side of the drawing. This 51 relay is not reverenced, or used, in any of the options and therefore should be removed from the drawing. 4) Options 14a, 14b, 15a, 15b, 16a and 16b all use an MVAR value equal to 120% of the aggregate generation MW value, instead of the

150% value used when the relays are located on the generator side of the GSU transformer. Presumably this is to account for the I squared Xt MVAR loss consumed in the GSU transformer. However, there is no mention of this fact in the Guidelines and Technical Basis document. To avoid confusion as to why different MVAR criteria are used, supporting technical justification / explanation should be offered in the document. 5) The example calculations for Options 4 and 10 are combined as a single identical set of calculations. This calculation is appropriate for Option 10 but not for Option 4. Referring to Figure 5, the 21 relays for Option 4 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 21 relay on each individual generator (Option 4) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. A separate calculation for Option 4 should be developed. For that Option 4 case the single generator apparent power (assuming three generators of equal size) would be 102/3 = 34 MW and 63.2/3 = 21 MVAR, which is 40 MVA for each generator. 6) The example calculations for Option 5 appear to be incorrect. Again referring to Figure 5, the 51V-R relays for Option 5 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 51V-R relay on each individual generator (Option 5) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. As such the 51V-R relay should be set to 130% of the maximum MVA rating of that individual generator. Again assuming three units of equal size, each generator would be rated 40MVA and therefore the 51V-R relay should be set to not operate below 1.3 x 40 = 52 MVA 7) The example calculations for Options 7a, 10, 8a, 9a, 11, and 12 illustrate a mixture of synchronous and asynchronous generators. However, there is no corresponding one-line drawing which corresponds to these examples. Because of this, it is difficult visualize the topology of this arrangement and where the corresponding relays would be located. If the SDT wishes to provide an example calculation where there is a mix of synchronous and asynchronous generation then we would suggest an additional figure be added (Figure 6) which would illustrate this type of connection.
Yes
No
FirstEnergy
Doug Hohlbaugh
No
FirstEnergy (FE) appreciates the attempt to develop a bright-line method but feel the approach taken is over complicating the standards. FE believes that the changes made to PRC-023 with the inclusion of requirements R7 and R8 and the associated Attachment C cause unnecessary confusion. FE proposes that the team remove R7, R8 and Attachment C from PRC-023 and retain a modified version of PRC-023, R1 item 6. Further, as supported in our comments below, we encourage the team to limit the applicability of PRC-023 to the TO and DP and the applicability of PRC-025 to the GO. FE believes it is imperative for NERC to develop its standards in a consistent approach in regard to terminology that is deemed "transmission" and those deemed "generation". We are concerned that the proposed changes to PRC-023 and PRC-025 overly complicate what most in industry already understand to be "transmission" and "generation" facilities. For example, NERC recently proposed errata changes to PRC-004 and PRC-005 to clarify that for a GO the requirements of those standards extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facility. It's difficult to understand why PRC-004 and PRC-005 seem to have clear TO and GO boundaries when it comes to reporting relay misoperations and performing relay maintenance, yet when ensuring relay loadability requirements are met things all of a sudden become much more complicated. To date, generation interconnection facility(ies) as used in NERC standards are generator owner assets, "generator lead", operated at transmission voltage levels. However, if the generator lead happens to be owned by a transmission owner, then it's understood simply to be a transmission line or transmission facility. The two relay loadability standards should maintain this same simplicity and PRC-023 should apply only to TO/DP and PRC-025 to the GO. We suggest that the team take this opportunity to introduce a formally defined NERC Glossary Term for generator interconnection facility. During the recent webinar the

team spent a fair amount of time indicating that when evaluating a generator interconnection facility(ies) as shown in Figure 1 and Figure 2 that it essentially comes down to the relay owner when determining which standard (PRC-023 or PRC-025) is applicable. The team indicated that if the GO owns the relay for line breaker(s) at Bus A then PRC-025 applies, but if the DP/TO owns the relay then PRC-023 applies. The team further described that the GO was left in PRC-023 to handle a situation where they may own relaying for line breaker(s) on networked transmission lines as shown in Figure 3. The team also cited they retained the GO for this situation to avoid a potential "registration tension". The perceived need for the GO in standard PRC-023 calls into question the facility rating for the network transmission line as established under FAC-008-3. NERC standards must maintain consistent philosophies in terminology throughout all standards and cover the most common system configurations. Any unique situations will need to be dealt with on a case by case basis between asset owners. Additionally, NERC drafting teams should not be writing standards to cover one-off configurations simply to address potential entity registration concerns. While FE strongly objects to the use of R7, R8 and Attachment C in PRC-023, if the team does not agree with our proposal to remove the GO completely from PRC-023 then as an alternate approach we support comments filed by Pepco Holdings, Inc. – PHI which suggesting adding the TO/DP to PRC-025 and removing R7, R8 and Attachment C from PRC-023. Either approach (FE's or PHI's) requires retaining item 6 of R1 in PRC-023. In summary, for PRC-023, FE proposes the following: 1.) Remove the Generator Owner applicability 2.) Remove Requirements 7 and 8 since they will be included in PRC-025 3.) Remove Attachment C 4.) Change Requirement 1 Criteria #6 to read as follows: "Set transmission line relays applied on transmission lines connected to generation stations remote to load directional towards the generator so they do not operate at or below 115% of the rating of the generator as calculated according to applicable NERC standards." Although not our preferred option, we also recommend the team considered the suggestion by PHI that would add the TO as an applicable entity to PRC-025 while also removing PRC-023 R7, R8 and Attachment C.
No
As stated above (Question 1) FE does not support the inclusion of Attachment C in PRC-023. See question 1 for more information. From a technical standpoint, we support Table 1 of PRC-025.
Yes
Yes
Yes
FE believes that that the term "generator interconnection Facility" should be a NERC defined term in the Glossary since it is used in other standards, ie, PRC-005, or at the very least, be defined within the standard(s). This term is only defined in the Guidelines and Technical Basis. In the Guidelines and Technical Basis, Figure 2 has a typo on the 3rd sentence and should read as follows: If the Distribution Provider or Transmission Owner owns these relay, they are responsible for them under PRC-023.
John Yale
Chelan County PUD
none
none
No
It seems that GSU and UAT would be subject to PRC-023 and PRC-025. It would be cleaner if one standard applied to GSU and UAT and the other to the transmission circuits.
Yes
Yes
Yes

1. Please, reconsider the applicaiton to small units that are "black start" or auxiliary units in a BES plant. Application of these requirements to a small (750kW) hydro unit that is black start is problamatic particularly due to the age of many of these units. It is difficult to see where loss of a unit of small size would impact the BES during this type of event. Please, consider a minimum size threshold for units where these requirements would be applicable. Perhaps 20MW as is used in the BES definition would be appropirate. Consider also an exclusion for a small unit, say less than 5MW, that is part of an aggregate plant of larger units that exceeds the 75MW plant threshold. An example is our 750kW hydro unit that is in the plant with ten 25MW units. It seems excessive to apply this to the 750kW unit. 2. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. 3. Clarify UAT and station service transformers. Footnote 1 says "Loss of these transformers will result in removing the generator from service." Does that mean it only applies to SS transformers that loss of will remove a unit from service? What about provisions for backup, multiple transformers and busses? Consider an hydro plant with 4 sation service busses and 12 generating units. Would this standard apply to all? This is very different from thermal stations where a unit would have a dedicated transformer that without its power the unit will trip. Consider liminting this only to transformers where loss would cause a direct trip of a BES unit, or eleminiate UAT ans SS transformers completely per comment 2. 4. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU, or FERC hydro nameplate criteria at best gate? 5. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. Consider a VSL based on the size of the generating unit or amount of generation that would be lost if the standard were not properly applied. A 20MVA unit would have a much lower impact on the reliability of the BES than a 500MW unit.
Barbara Kedrowski
Wisconsin Electric
Wisconsin Electric
Barb Kedrowski
Agree
NAGF
Operational Compliance
Ed Croft
Yes
Content is good. However - the two standards should refer to EXACTLY the same table of Relay Loadability Evaluation Criteria with EXACTLY the SAME OPTION #s for each Relay Type/Application.

The table could stand on its own and each record be labeled with PRC-025 and/or PRC-023 applicability (new column(s)).
Yes
But...see comments for Question #1.
Yes
See comments for Question #1. In addition, Figures 1,2 and 3 could be clarified by 1) labelling the Generator Interconnection Facility with a pointer and parentheses, 2) include table with columns for Relay Owners, Function of Owner and Applicable Standard. This way, a quick glance at the figure can clarify which standard is applicable (rather than having to decipher the caption).
Yes
Editorial note: To aid with distinguishing between options: underline the words "is necessary" and "is not necessary" for "Implementation Date" columns.
Clem Cassmeyer
Western Farmers Electric Cooperative
Western Farmers Electric Cooperative
Caleb Muckala
Agree
Western Farmers Electric Cooperative
No
See comments to question 5
No
See comments to question 5
Yes
Many generation Facilities, that are part of the Bulk Electric System, became commercial in the 1950's, 1960's, 1970's, 1980's and 1990's. These Facilities should be Grandfathered in. Many of these units, although reliable, it may not be cost effective to obtain compliance with PRC-025-1. Many of these Facilities would be forced to either: (1) implement very expensive upgrades to existing equipment, (2) replace existing equipment, (3) retire the Facility. It's my opinion this is not consistent with the economic rational NERC is attempting to achieve. Secondly, the Violation Risk Factor of High, seems extreme because several other standards address generator reliability (Under-frequency, Misoperations, Protection System Maintenance and Testing, Generator Verification). These standards, have resulted in many generation Facilities having undergone relay coordination studies to prevent an occurrence similar to the 2003 "blackout."
Michael Mayer
Delmarva Power & Light Company
Pepco Holdings Inc & Affiliates
David Thorne
Agree
Pepco Holdings Inc. & Affiliates
NICOLE BUCKMAN
Atlantic City Electric Company
Pepco Holdings inc. & Affiliates
David Thorne

Agree
Pepco Holdings Inc. and Affiliates
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
Yes
Yes
Yes
The NSRF remains concerned that the proposed calculations for the distance relays will adversely affect reliability of the BES by requiring generators to pull back distance reaches too far which could lead to reduced rely coverage (at least for backup relaying) or longer delays for coordination. Some sample calculations performed by NSRF members show that distance reaches need to be pulled back more than 30%. The NSRF members believe that this is most likely due to the more conservative relay load limit angle calculations at 30 degrees rather than former MidContinent Area Power Pool (MAPP) criteria which used line Maximum Torque Angle calculations which typically averaged near 70 – 85 degrees. Sample MAPP Relay Load Limit Calculation: (0.85*kV)^2 / (Z1max*cos(max torque angle – line power factor angle) NSRF sample calculations show that many generators may require 21 distance setting changes based upon this proposed standard, potentially resulting in potential reductions of relay backup coverage for lines leaving some generating stations. This will put a much higher risk and responsibility on the TO too have extremely reliable protection for the lines. We will no longer be able to trip the generator off in a backup mode if the TO does not clear the phase fault at end of line. This appears to conflict with R1, unless the standard is mandating the installation of additional equipment such as redundant relays systems to maintain reliable fault protection. The NSRF would ask the NERC Standard drafting team to work with NSRF members to help verify the basis for the new calculations and if this does in fact reduce relay coverage or require entities to install additional relaying to maintain system reliability as mandated in R1.
Mark Yerger
Potomac Electric Power Company
Pepco Holdings, Inc & Affiliates
David Thorne
Agree
Pepco Holdings Inc. and Affiliates
Jonathan Meyer
Idaho Power Company
n/a
n/a

Yes
Yes
Yes
Yes
No
Alice Ireland
Xcel Energy
n/a
Alice Ireland
Yes
No
For 51 relay that is installed on the high side of GSU, we suggest it should be an acceptable option if the 51 relay setting meets R1 Criteria 11.
No
In the last paragraph on page 19 of the clean version of the PRC-025-1 Guidelines and Technical Basis, the following sentence appears: "Phase time overcurrent relays applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard." This typically would be the case for UAT's connected to the generator bus. However, for system connected auxiliary transformers as shown in Fig 6 on page 20, it is very unlikely that the time overcurrent relays protecting the system connected transformers will act to trip the generator directly or via lockout as this is a different zone of protection and to do so might result in an unnecessary challenge of the unit's overspeed protection. Instead, these overcurrent relays will trip the source breakers feeding the system connected auxiliary transformer but will not act to directly trip the generator. The generator will ultimately trip because of the resultant loss of power to the auxiliary system when the source breakers feeding the auxiliary transformer are tripped. The loss of auxiliary power will likely result in some form of a turbine/prime move trip and the generator breaker will be tripped open once power output drops to zero. In this manner, unit overspeed protection is not unnecessarily challenged. It seems that the quoted sentence on page 19 only serves to confuse the matter. If the goal of this setting requirement is to not to have the plant trip due to a loss of auxiliary power based on overly conservative setting of overcurrent relays, it is immaterial whether the overcurrent relays act to trip the generator directly or via lockout or auxiliary tripping relay or if the plant ultimately trips because a loss of auxiliary power caused by overcurrent relays opening source breakers to the system connected auxiliary transformer. We recommend the quoted sentence be stricken from the guideline and technical basis document.
Yes
Yes
1) Applicability: In the applicability sections, we suggest you replace the phrase "BES generating unit or generating plant" with "BES generating unit or BES generating plant" to be more clear. 2) M1: We recommend you add “simulation results” as acceptable evidence in Measure M1. (reason: Some people may choose to do PRC023 check in the CAPE simulation.)
Michael Falvo
Independent Electricity System Operator
NPCC

Michael Falvo
Yes
Yes
Yes
Yes
No
PacifiCorp
Ryan Millard
Yes
Yes
Yes
Yes
No
Wryan Feil
Northeast Utilities
Wryan Feil
Wryan Feil
Yes
Yes
Yes
Yes
No
SERC Protection and Controls Subcommittee
David Greene
Yes
No
There is a discrepancy between the relay functions listed in PRC-023-3 Attachment A and those identified in PRC-023-3 Attachment C Table 1 and PRC-025-1 Attachment 1 Table 1. PRC-023-3 Attachment A includes under 1.6, “Phase overcurrent supervisory elements (i.e., phase fault

detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." These schemes are not accounted for in the Table 1 of either proposed standard. Given these schemes are required to meet loadability criteria on transmission lines not meeting the "generator interconnection facility" designation (i.e. networked lines), the exclusion of the schemes from generator loadability criteria creates confusion. Loadability criteria should be included for "Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications" in Table 1 of both PRC-023-3 and PRC-025-1.
Yes
Yes
Yes
There were three one-line reference drawings described on the webinar. Suggest adding text to these reference drawings or add descriptive wording in reference documents to better explain responsibilities of relay owners for these various configurations. On the webinar there were repetitive questions about these configurations so this would indicate confusion. Also, would suggest adding another drawing to illustrate when you have a generating station where the GO owns GSU relays and the TO owns relays between the GSU and switchyard to clarify that the TO is only responsible for R7 in PRC023-3 and not R8 since the GSU relays are a GO asset.
Nazra Gladu
Manitoba Hydro
Manitoba Hydro
Nazra Gladu
Yes
Yes
(1) Manitoba Hydro suggests eliminating Table 1 from one of the standards and referencing it in the other standard, since both PRC-023-3 and PRC-025-1 are already very lengthy standards.
Yes
Yes
Yes
(1) Section 3.1.1, PRC-025-01 - the repeated word "Facilities" seems unnecessary. For clarity, remove the last instance of the word "Facilities" in the statement: "Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities." (2) Section 3.2 - it would be useful to add criteria that define which generator units should be included as associated with the BES. Alternatively, should this standard refer to the BES definition for which generator units in this standard will apply to? (3) Section 3.2.5 - It is unclear what elements should be included in this section - Collector lines only? What size (MVA) of generating source that the collector line has to be on to qualify as one of these elements? (4) Implementation Plan, PRC-023-3 - it would be helpful to include the implementation plan within the standard. (5) PRC-023-3, Purpose - suggest re-wording to the following "…not interfere with a system operators ability to take remedial action to protect system reliability….". (6) PRC-023-3, Purpose - capitalize "system operator" because it appears in the Glossary of Terms. (7) PRC-023-3, Applicability, Functional Entity - capitalize "protection system" because it appears in the Glossary of Terms. (8) PRC-023-3, 4.2.1.3 - 'BES' should be written Bulk Electric System (BES) since it is the first appearance of the word. (9) PRC-023-3, 4.2.3.1 - should Transmission lines be written "Transmission lines (and paths)"? (10) PRC-023-3, R1, 4 - capitalize the words "power transfer capability" because it appears in the Glossary of Terms. (11) PRC-023 and PRC-025 - capitalize the words "transmission lines" throughout the document(s). (12) PRC-023 and

PRC-025, D. Compliance 1.1 - the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (13) PRC-023-3 — Attachment B, Circuits to Evaluate - replace the acronym “BES” with the words “Bulk Electric System”. (14) PRC-023-3 — Attachment B, Criteria, B2 - write out the words for “IROL” then use the acronym thereafter. (15) PRC-023-3 — Attachment C - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”. (16) PRC-025-1 – Attachment 1: Relay Settings - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”.
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst
Anthony Jablonski
Yes
Yes
No
1) There appears to be an error in the Guidelines and Technical Basis document on page 23 for option 15b. It indicates that the Reactive Power output that equates 120% of the maximum gross Mvar output whereas Table 1 states 100%. 2) A statement should be inserted that the iterative calculation stopped because the change was < 1%. This applies to options 1b & 7b on page 31 and option 2b on page 38. Also, if an entity knows the resistive and reactive impedances of the transformer, the entity could directly calculate the low-side GSU voltage from the high-side voltage, the per unit current through the GSU and the full impedance of the transformer.
Yes
Yes
1) In Attachment 1, it is not clear that the fifth bulleted exception regarding protection systems that detect generator overloads needs or should be as specific as to cite the 7 seconds at 218% of full-load current operating point or characteristic curve. Typically for a fault right on the generator terminals, the current decays in a couple of seconds to around full load current even with the AVR in service. Even during field forcing, it is more likely that the field overcurrent relay would operate rather than a generator overload relay. Therefore, the exclusion does not appear to be needed. If the exclusion is needed, it is recommended that the exclusion be stated in a more general way such as the following: Protection systems that detect generator overloads that are designed to coordinate with the generator short-time capability by utilizing a relay characteristic set to operate no faster than the capability curve and supervised to prevent operation below 115% of full-load current. 2) The word ‘Each’ appears to be missing in Requirement R8 of PRC-023-3. ‘Each’ should be inserted at the beginning of the requirement before Transmission Owner and Distribution Provider. 3) Since there are cases where redundant UATs that allow a generator to continue to remain in service when one UAT trips, this may be rationale to revise 3.2.3 of the Applicability section to indicate exclusion for these configurations. Alternatively, it could be addressed in the Guidelines and Technical Basis document. 4) The Regional Reliability Organization (RRO) is referenced within both standards and it was ReliabilityFirst’s understanding that the term RRO was to be removed from all the standards. In Order 693, Paragraphs 146-148 and paragraph 157 state “The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate.” ReliabilityFirst suggests replacing the RRO with the Planning Coordinator (PC) or other registered function the SDT determines to have the wide area view and be responsible for determining what these settings and or values should be.
David Jendras

Ameren
Ameren Compliance
Eric Scott
No
(1) For consistency, we believe that PRC-023-3 requirement R7 should only apply at 200kV and above. Therefore, we request the SDT to change 4.2.3.1 to 'Transmission lines operated at 200kV and above that are used…"
No
(1) We ask the SDT to clarify that 'nameplate MVA rating' means the 'generator nameplate MVA rating'. Therefore we request that the SDT either add a statement "Unless otherwise stated, 'nameplate MVA rating' means the 'generator nameplate MVA rating' throughout Table 1", or insert 'generator' before 'nameplate MVA rating'.
No
(1) We request the SDT to add a multiple winding transformer example. We recommend that the SDT include an example with equally rated CTGs connected to equally rated dual secondary transformer windings stepping up to a single high voltage winding, because it is commonly used. (2) The MW capability reported to the Transmission Planner changes by a very small amount from time to time. As written we believe that this could trigger a significant amount of documentation. We request the SDT to show in your example (s) how an increased margin would address such a small change (e.g. a 2% increase from the originally documented value) before triggering such a review. (3) On page 2 of the Guidelines and Technical Basis document, we ask the SDT to delete 'Generator Owner' from the last sentence of Figure 2 caption.
Yes
Yes
(1) The generator overload protection exception on page 8 for "extremely inverse characteristics" (5th bullet-dot) is a major improvement, but we believe that the term "full-load current" needs clarification. We ask the SDT, is this current at 100% of the gross MW capability reported to the TP, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or the smallest of these? (2) We believe that Blackstart Resources should be excluded because there is no technical basis for including them. On the contrary, it is more important to assure Blackstart Resources are adequately protected and available for restoration in the extremely unlikely event that a wide-area blackout occurs. Also, we believe that there is no evidence that the tripping of a Blackstart Resources has contributed to widespread outages. In our experience, these resources are below the 20MVA threshold and even if they were on-line and tripped their impact to the BES are minimal. (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.
Thomas Foltz
American Electric Power
Does Not Apply
Does Not Apply
No
AEP believes that both documents would benefit from the inclusion of a simplified GO/TO interface diagram showing the overlap and applicability of the two standards within the opening section of each standard. Clarity needs to be provided to PRC-023-3 regarding the proper consideration of GO-owned transmission line protection systems. It must be understood that for load responsive relays subject to R7 and R8, the responsibility to perform loadability evaluations is on whoever is the owner of the Protection System. Regarding PRC-023-3, it is unclear exactly what facilities are included in the term "BES Generating Unit". It is requested that this be clarified. AEP also requests clarification on the voltage levels applicable to Regarding PRC-023-3 R7. Section 4.2.3.1 currently applies to "transmission lines" which implies that all voltage levels would be subject to this requirement. It is requested that this be revised to clarify exactly what voltage applies.

No
PRC-023-3 must be clear in stating that, if a Transmission or Distribution line used solely to export energy directly from the GU has its own circuit breaker, then the existing R1 through R5 criteria should be applied based on the rating of the line. PRC-023-3 appears to exclude relays directional toward the Generating Unit. For example, if you attempt to evaluate loadability for two-terminal 345kV line to a windfarm, it appears to be applicable to both PRC-023-3 4.2.1 and 4.2.3. This would make it difficult to determine what Transmission lines are subject to evaluation and which requirement to apply, R1 or R7. Based on the current draft, it is not clear what criteria set to apply. The criteria in Table 1 is based on Generator's power while the criteria in Requirement 1 is based on circuit ratings. It needs to be clarified which criteria set is to be applied. A second example is in a situation when a loadability evaluation is needed for a two-terminal line that is definitely not applicable to 4.2.1., but *is* applicable to 4.2.3. The intent of having two standards appears to be to have the relays on the Generating Unit end owned by the GO, set according to criteria R1 in PRC-025-1; and to have the relays on Generating Unit end owned by the TO, set according to criteria R7 in PRC-023-3. In this example, there would appear to be no criteria required to set relays on the end external to the Generating Unit, for relays owned by either the GO or TO. Clarification is needed to define responsibility based on Protection System ownership as well as to clearly convey the applicability of remote protection systems.
Yes
No
Regarding PRC-025-1: While AEP appreciates the factors considered by the drafting team when developing the proposed implementation plan for PRC-025-1, the plan as proposed will not afford adequate time for large Generator Owners to comply with the standards. AEP has 119 generating units and 2 wind farms that are applicable to PRC-025-1. The resources needed to evaluate the generating units for compliance with PRC-025-1 and PRC-023-3 will also be engaged in implementing the new NERC standards PRC-019-1 and PRC-024-1. For these reasons, AEP believes a phased implementation plan for PRC-025-1 is more appropriate. Such a plan would require entities to show that a minimum percentage of their applicable relays are compliant within a specified time frame. For example: * Entities shall demonstrate that 30% of their applicable load-responsive protective relays are fully compliant with R1 within 48 months of the effective date of this standard. * Entities shall demonstrate that 60% of their applicable load-responsive protective relays are fully compliant with R1 within 60 months of the effective date of this standard. * Entities shall demonstrate that 100% of their applicable load-responsive protective relays are fully compliant with R1 within 72 months of the effective date of this standard. Regarding PRC-023-3: The proposed revision could significantly impact Transmission Owners. Additional research is being conducted within AEP Transmission to determine the extent of that impact. It is possible that the proposed implementation plan would not provide adequate time to achieve compliance with the standard if it is determined to impact a high volume of facilities. Additional research will be needed before a recommendation be made on the extent the additional time required. It is still unclear when TOs, GOs and DPs will be required to complete loadability evaluations for any circuits below 200kV included by the Planning Coordinator per Attachment B. It is understood that we will have 39 months to apply the initial list. There is confusion however on whether or not the 39 months applies to new inclusions to the list. AEP requests that this time frame be clarified and included in the standard, as it is information needed to maintain compliance on an ongoing basis.
Yes
System fed auxiliary transformers whose loss would not result in an instantaneous generating unit trip, and for which operators would have opportunity to reconfigure the plant auxiliary load before a unit trip occurs, should be excluded from this standard. However, if the SDT intends the standard to be applicable to all system fed auxiliary transformers, we recommend removing the text "…that trips the generator either directly or via an interposing/lockout relay" from the standard. This statement is similar to language that entities have used to exclude system fed auxiliary transformers that initiate a process shutdown trip from the scope of other NERC PRC standards. During a disturbance in which system voltage becomes depressed, the generator will respond by increasing excitation in an effort to compensate for the voltage loss. This will result in the generator terminal voltage being greater than the system voltage. For this reason, AEP recommends that settings for applicable relays installed on the generator side of the GSU be based on a generator bus voltage of 1.0 per unit at the generator

terminals, rather than a generator bus voltage calculated from 0.85/0.95 per unit of the GSU high-side nominal voltage.
Chris Mattson
Tacoma Power
Tacoma Power
Chris Mattson
Yes
Yes
Yes
Yes
Yes
Comments 1-4 below pertain to PRC-025-1. 1. Referring to Attachment 1, are phase fault detectors used in current-based local breaker failure schemes excluded from PRC-025-1? 2. Referring to Attachment 1, Footnote 3 still has the terms "no-load tap changers (NLTC)" and "on-load tap changers (OLTC)." 3. Referring to page 22 of 68 of the redlined Guidelines and Technical Basis, the first paragraph after "Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)," change "…for these relay…" to "…for these relays…" (There are also other instances of this issue.) 4. Referring to page 20 of 68 of the redlined Guidelines and Technical Basis, would the UATs shown in Figure 6 necessarily be applicable to PRC-025-1? It seems that phase time overcurrent relays applied to UATs like these might not "act to trip the generator directly or via lockout or auxiliary tripping relay." Comments 5-8 below pertain to PRC-023-3. 5. Referring to Attachment C, why are only two of the bulleted exceptions shown in PRC-025-1 Attachment 1 brought over? 6. Referring to page 12 of 13 of the redlined Implementation Plan, change "…were added to address to situations…" to "…were added to address situations…" 7. Referring to page 13 of 13 of the redlined Implementation Plan, last row in the table, are references to R7 supposed to be references to R8? Additionally, change "…equally and efficient…" to "…equally efficient…"
RoLynda Shumpert
South Carolina Electric and Gas
Self
RoLynda Shumpert
Yes
Yes
Yes
Yes
No
Rick Terrill
Luminant Generation
Luminant Generation
Rick Terrill

No
Luminant recommends the following: (1) Load responsive relays identified in PRC-025-1 and 023-3 connected on generator breaker(s) at the GSU high side and are primarily used for backup of failed transmission line relaying shall use options in Attachment C (PRC-023-3) and Attachment 1 (PRC-025-1). (2) Load responsive relays identified in PRC-023-3 and connected on the high side of the GSU that are primarily used for transmission line protection shall use the existing criteria in PRC-023-2, Requirements R1 through R6. The above recommendations can be done by adding diagrams in PRC-023-3 and clarifying Figures 1, 2, and 3 in PRC-025-1.
No
Luminant disagrees that the criterion for setting load responsive relays is clear because of the bright line is vague. Luminant recommends that each standard be clear in addressing the relay setting criteria by its primary application.
No
Figures 1, 2, and 3 do not provide a sufficient bright line between the application of PRC-025-1 and PRC-023-3 for setting criterion. Luminant recommends that additional information be added that identifies that a load responsive relays located on the transmission line breaker at Bus A and are primarily installed for transmission line protection use PRC-023-3 criterion Requirements R1 through R6 (regardless of the number of generators or transmission lines connected to Bus A). Load responsive relays located on the high side of the GSU and are primarily used for failed transmission line protection should use PRC-023-3 (Attachment C) or PRC-025 (Table 1).
No
Luminant recommends that the phrase "where relay replacement is not required" and "where relay replacement is required" add the word removal; i.e., "replacement or removal".
No
David Gordon
Massachusetts Municipal Wholesale Electric Company
n/a
n/a
Agree
North American Generator Forum
Mark Stein
Tri-State G&T
Tri-State Generation and Transmission Assoc
Mark Stein
No
The generator overload protection exception added to Draft 3 for extremely inverse characteristics is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU?
Yes

1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. 2. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 3. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 4. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard.
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
Yes
No
See Comments for Question #5
Yes
Yes
: The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." Unit Auxiliary Transformers (UAT's) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3. The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities' UATs in Section 3.2.3 do not belong in this standard as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT's lack of impact on generator loadability should be considered by the SDT. A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). 2.) The generator overload protection exception added to Draft 3 for "extremely inverse characteristics" (5th bull-dot) is a major improvement, but the term "full-load

current" needs clarification The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that "full-load current" is understood to be the generator nameplate MVA at rated voltage 3.) The overload protection exception added to Draft 3 for "extremely inverse characteristics" should be applied for UAT's as well if eliminating UAT's in its entirety (per comment #1 above) does not prove feasible. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. 8.) The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing.
North American Generator Forum Standards Review Team
Patrick Brown
No
See comments to question 5 below
Yes
1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. 2. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? 3. The exception of comment #2 above, which is presently limited to generator overloads, could be applied for UATs as well if eliminating this equipment in its entirety (per comment #1 above) does not prove feasible. 4. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection

without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 5. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 6. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 7. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above.
Michelle R. D'Antuono
Ingleside Cogeneration LP
Individual -- Ingleside Cogeneration LP
Michelle R. D'Antuono
No
Even though the language in both standards draws a technically accurate bright line, Ingleside Cogeneration believes that the addition of the generator relay criteria to PRC-023-3 is confusing at best. It appears that the issue has to do with the ownership of the relays. In some cases the DP and/or the TO owns a load responsive relay that is protecting generation equipment. Conversely, some GOs own load responsive relays that protect transmission equipment. If the concept of the two standards is that PRC-023-3 applies to transmission-related relays and PRC-025-1 applies to generation-related relays, than the owner of the relay is not a gating factor. This means that the applicability table for both standards would include DPs, GOs, and TOs. There would be no repeated criteria between the standards in this arrangement – and less confusing in our view.
Yes
Yes
No
Ingleside Cogeneration LP does not agree with the 100% compliance approach that the drafting team has taken in regard to PRC-025-1. Although FERC Order 733 is cited multiple times as the reliability need, there are real dollars that the industry will need to expend to analyze and replace load responsive relays for generators of any size. We do not read Order 733 the same way – and FERC has accepted exceptions for low-impact facilities in the past.
Yes
In the previous posting, the project team requested our estimated compliance costs and comments on the RSAW. Both of these projects are components of risk-based compliance – which Ingleside Cogeneration LP fully supports. However, it appears that these are not considerations at all in the latest postings. We are not sure what has changed in the intellectual basis of risk-based compliance, but it seems we have taken a step backwards. The rationale for far too many of the project team's consideration of comments was that FERC Order 733 mandated some action. Since FERC has been generally supportive of the risk-based initiative, this type of response is inconsistent with their position in our view.
Western Area Power Administration
Lloyd A. Linke
Yes
Yes

Recommend adding reference to Table 1 - Options 7, 8, 9, 10, 11, 12 – Relay Type back to options 1, 2, 3, 4, 5, 6 for applications on the generator side of the GSU. The language and reference used in the Relay Type column for Options 1-6 added clarity and should be mirrored in Options 7-12.
Yes
No
Brenda Hampton
Luminant Energy Company LLC
Luminant
Brenda Hampton
Agree
Luminant Generation Company LLC
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
John Bee
Exelon and its affiliates
NA
NA
The Constellation Energy Nuclear Generation (CENG) NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” Section 3.2.3 of PRC-025-1 requires clarification simply because the Unit Auxiliary Transformers (UAT’s) are not necessarily directly connected to the generator, but there are indirect link to the generator operation. The UAT’s are ok to be included to the applicability of this standard, but section 3.2.3 could use more detailed explanation. Moreover, the webinar on 5/15/13 pointed out that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power drawn of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. CENG state that Facilities, UAT’s in Section 3.2.3 is appropriate to include it, but there need to be a specific explanation as to the affect of MW due to grid disturbance affect the generator output. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT’s lack of impact on generator loadability should be considered.

Daniel Duff
Liberty Electric Power LLC
none
none
Agree
Generator Forum SDT, as submitted by Patrick Brown, Essential Power
No
Oliver Burke
Entergy Services, Inc. (Transmission)
Entergy Services, Inc. (Transmission Owner)
Oliver Burke
Yes
Yes
No
The Guidelines are still not clear about what to do with start-up transformers when used in lieu of the UATs (Unit Auxiliary Transformer).
Yes
Yes
The implementation plan may be challenging to meet and an alternative implementation plan may need to be provided based on the population of load-responsive protective relays determined affected by this standard and the subset of which that will require replacement relays. Additional resources will be required to (1) determine the population of load-responsive relays at each generating station, (2) determine the settings of the existing load-responsive relays, (3) calculate load-responsive relay settings per the reliability standard, (4) compare the existing load-responsive relay settings to the calculated load-responsive relay settings to determine the population which are acceptable as-is, the population that require a settings change, and the population that requires replacement, (5) schedule the population of load-responsive relays for settings change, (6) order replacement load-responsive relays for the population determined incapable of meeting the reliability standard and schedule relay replacement. The resulting calculations and set-point datasheets will form the basis for the load-responsive relay settings and evidence for meeting the standard’s requirements.
Dominion
Randi Heise
Yes
Dominion agrees that the addition of requirements in PRC-023-3, R7 and R8 strengthens the bright line between the two standards. However, we do not agree with use of the term “Transmission’ in 4.2.3.1 as it is our position that it does not conform with the intent of the term as defined in the NERC Glossary of Terms. We therefore suggest the sentence be revised to read “Lines that are used solely to export energy directly from a BES generating unit or generating plant to the network.”
No
Dominion believes that the appropriate designation of “Real Power output” is the generator nameplate rating however Dominion does recognize that the addition of “gross” prior to MW is an improvement

to the table wording.
Yes
Yes
Yes
PRC-025 -1 Requirement 1: remove the following words: "…while maintaining reliable fault protection." It is not possible for entities to measure or prove this statement. The wording, "while maintaining reliable fault protection", is also included in the Introduction section of PRC-025-1 Guidelines and Technical Basis. The inclusion "describes that the Generator Owner is to comply with this standard while achieving its desired protection goals." Dominion believes that the Generator Owner understands the compliance obligation based upon the requirements of the standards and that the inclusion of the referenced language should be excluded based on the inability of the entity to measure or provide evidence of maintaining reliable fault protection. PRC-025-1: Redline - Page 6 of 18 Table of Compliance Elements; An indication of Lower VSL. Moderate VSL or High VSL needs to be determined with regard to R1. Dominion disagrees with the "all or nothing" approach to VSLs. PRC-023-3 Implementation plan; Redline Pages 3-6, R1-R6 the Requirement wording (in the Applicability column) does not exactly match the Requirement wording in the standard. Dominion suggests correcting the wording to match the Standard as written. PRC-025-1 @ figure 3 – Dominion does not necessarily agree that these lines are part of networked transmission and therefore would not be considered as generator interconnection Facilities. Dominion believes the designation of the lines should be based on registration of the asset owner and will be providing supporting comments in response to the FERC NOPR in docket # RM12-16-000.
Chantel Haswell
Public Service Enterprise Group
PSEG
Chantel Haswell
No
For UATs per PRC-025-1, that are energized from the system (as opposed to from the GSU), the SDT seems to assumes that no TO or DP owns the load responsive relays for these UATs. Has that been verified by the SDT?
Yes
The SDT needs to confirm that UATs that are energized from the system (not the GSU) at high-side voltages that are below 100 kV are part of the BES before imposing standards on UAT load-responsive relay settings.
Duke Energy
Michael Lowman
Yes
Yes
No
Examples of calculations are helpful. However, more details on the root of the calculations are needed. Exclusively calculating values on a per unit basis would add more clarity.
No
Duke Energy schedules some of its generating units on a 24 month cycle for minor outages and a 96 month cycle for major outages. This would make the current Implementation Plan very expensive and

difficult to comply with if relay replacements are required. [Duke Energy suggests a 48 month and 96 month Implementation Plan. This would allow for the industry to use existing outage schedules, keeping overall costs at a minimum.]
No
Bret Galbraith
Seminole Electric Cooperative Inc.
Seminole Electric Cooperative, Inc.
N/A
Yes
Seminole Electric reasons that the NERC SDT has not provided sufficient evidence to warrant a High VRF and a Severe VSL for penalties associated with proposed Standard PRC-025-1.
Russ Schneider
Flathead Electric Cooperative
N/A
N/A
No
it is not clear to me how this would impact very small dispersed generators.
Yes
Do not support including Elements utilized in the aggregation of dispersed power producing resources. This seems to have the potential to rope very small generators into significant compliance burdens for very little reliability benefit.
Santee Cooper
Terry L. Blackwell
Yes
Unit Auxiliary Transformers (UATs) should be removed from this standard (Facilities Section 3.2.3). The purpose of this standard is “To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage.” The intent as stated in the Application Guidelines is to pertain to relays that “are affected by increased generator output in response to system disturbances.” UATs do not fit this criteria. Addressing generating plant unit auxiliary transformers does not have to translate into creating a standard requirement for that equipment. An investigation and evaluation of the protection system for unit auxiliary transformers should be considered by the standard drafting team and deemed to be not related to generator loadability and fulfill the FERC order to address the subject.
Robert Rhodes
Southwest Power Pool

N/A
N/A
Yes
Yes
Yes
Yes
Yes
For the sake of clarity, I would suggest adding the phrase ‘to the generator’ at the end of the Purpose of PRC-025-1. This is implied in the existing language but it wouldn’t hurt to add this and specifically indicate what damage you’re referring to. For consistency within the requirements and between the requirement and corresponding measure in this situation, please add ‘Each’ at the beginning of Requirement R8. This makes R8 consistent with the rest of the requirements and with Measure M8.
JEA
Tom McElhinney
No
While it has been demonstrated in the 2003 blackout that a small percentage of generating units did trip off line prematurely due to conservative setting of generator protection systems, no evidence has been provided that transformer tripping contributed to the cause of the generation outages. The sole purpose as stated by the SDT for including transformers is a directive from FERC. We believe that there should be some evidence as to the benefit of preforming protection modifications to transformers and that they should not simply be included until a study can be performed to show the cost benefit analysis and therefore recommend that transformers be excluded during this phase and be incorporated into a phase III. If transformers are to be included, an exception should be provided to allow the start-up transformer to be used to provide auxiliary power in case of failure of the auxiliary transformer. BES reliability is better served by allowing this exception (which will occur very infrequently) than to keep the generating unit off line for fear of being out of compliance with a standard.
No
Considering that applying new settings and testing will require a major outage, we believe that 48 months is not a sufficient time frame for full implementation when existing equipment can be used and relay replacement is not required. We recommend 72 months be allowed even in the case where existing equipment can be used. It may take a year or more to perform the calculations and evaluated equipment and then another 5 years for a major planned outage to occur.
Yes
We would like to see modifications to violation severity levels. While we recognize the SDT is following NERC binary guidelines “pass/fail”, this needs to be improved. The idea that either they “applied” or “did not apply” settings must result in a “severe” violation level does not match the reality that missing 10 out of 20 poses a greater risk to the BES than 1 out of 100.
DTE Electric
Kent Kujala
Agree
No
Comments: The distinction is not clear between these two standards regarding generator owner

relays that look toward the transmission system. Perhaps specifying the application location of the relay (CT and PT inputs) would help in clarifying the differences
No
Comments: Suggest that allowing 72 months to become 100% compliant for both 4a and 4b would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Bonneville Power Administration
Jamison Dye
No
The requirements for generator interconnection facilities in PRC-023-3 apply to Transmission Owner's (and Distribution Provider's , and the requirements for generator interconnection facilities in PRC-025-1 apply to Generation Owner's. BPA believes that putting requirements for the generator interconnection facilities in two separate standards and making the applicability of the standards different is confusing and unnecessary. BPA recommends that all interconnection facilities, regardless of ownership, should be covered within one standard to provide uniformity in the application of settings for interconnection facilities.
No
Example: A 230kV line that is connected between a substation Terminal and a Generating station. (Comment 1) This circuit fits under 4.2.3 of PRC-023-3, so it is subject to Requirement 7. The circuit also fits under 4.2.1, so it is subject to Requirements R1 throughR5. BPA believes it should only be subject to R1 throughR5 or R7, not both. (Comment 2) R7 requires that the load responsive relays be set in accordance with PRC-023-3, Attachment C. BPA would like to point out that the phase distance relays at the substation terminal looking toward the generation are not covered by Attachment C and believes this creates a problem as it makes it impossible for these relays to be set in accordance with Attachment C. The same problem also exists for relays at the terminal of the generator step up (GSU) transformer looking toward the generation, recognizing that this is not a normal application. Based on these issues, BPA believes Attachment C should address all relays, not just those looking towards the Transmission system.
No
While the Guidelines and Technical Basis provides useful information, BPA is concerned that this document will not be approved by FERC as part of the standard and thus the standard must be capable of standing on its own. For this reason, BPA requests that clarification provided in the Guidelines and Technical Basis document be included into the standard specifically in regards to 'generator interconnection facilities'.
Yes
Yes
Comments: (1) The use of the term generation interconnection facility without an official definition of the term is concerning to BPA. BPA believes that this term may have different meanings between entities. For example, the entire Bulk Electric System (BES) together with all distribution systems could be considered to be a generation interconnection facility because the purpose of the BES and distribution systems is to interconnect generation to the end user (load). Only under the Guidelines and Technical Basis is a description of what a generator interconnection facility found.BPA is concerned with this approach as it does not give an official definition, and this document is not part of the standard. Additionally, BPA believes the description of generator interconnection facility given in the Guidelines and Technical Basis creates problems. The description provided is that the generation interconnection facility consists of elements between the generator step up transformer (GSU) and the interface with the portion of the BES where the Transmission Owner (TO) takes over the

ownership. In many cases the TO owns the line that connects to the generator step up (GSU) transformer and there are no elements between the GSU and the TO. According to this description there is no generation interconnection facility. Due to the ownership arrangements of transmission, generation, and their interconnection facilities throughout the country are highly variable, BPA believes it is not suitable to develop a definition of generation interconnection facilities based on ownership. Such a definition may reflect the ownership arrangements within a particular region while it does not take into account various other arrangements that may exist. BPA recommends for the drafting team to provide a definition of generation interconnection facility that takes into account the various ownership situations that may exist. (2) BPA believes the use of the word associated in the purpose statement of PRC-025-1 as well as in Section 3.2 Facilities is too vague and recommends this term be changed to “whose function is the protection of generation Facilities…” in the purpose statement and Section 3.2 be rewritten to read “3.2 Facilities: The following Bulk Electric System Elements, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:”
Tennessee Valley Authority
Dennis Chastain
TVA electric generators segment agrees with comments submitted by the North American Generator Forum (NAGF).
Yes
Yes
No
Yes
Is the intent of this standard to identify the lines in their normal configuration and not for contingency events? For example, referring to Figure 3 from the Webinar, if a line is lost, causing the system configuration to change to what is shown in Figure 1, does this mean that the configuration then is considered to fall under R7?
ACES Standards Collaborators
Jason Marshall
No
There is definitely much clearer delineation between what is required in PRC-023 by the Transmission Owner and Distribution Provider and in PRC-025 by the Generation Owner for generator step up transformers, generators, auxiliary transformers and generator interconnection facilities. However, PRC-023 still has other requirements that are applicable to Generators Owners that do not make sense, create compliance risks and, thus, detract from reliability by distracting the Generator Owner from value added reliability activities. For example, PRC-023 R1 is still applicable to the Generation Owner and it should not be. A Generation Owner does not own transmission beyond the generator interconnection facility. This is recognized in Project 2010-07 Generator Requirements at the Transmission Interface and NERC’s work surrounding the GO/TO and GOP/TOP registration issues. If a Generator Owner owned transmission beyond the generator interconnection facility, they would be registered as a Transmission Owner. Thus, the Generator Owner will be stuck essentially going through a registration exercise for every compliance activity to prove that the requirements do not apply because they do not own transmission facilities. Other requirements in PRC-023 that require removal of Generator Owner include R2, R3, R4, and R5. Until these removals occur, we will not be able to support the standard.
Yes
The table is much clearer than in past versions. However, we do recommend one minor additional change. The option numbers should be reset to 1 for every application and relay type combination since they are truly options within those combinations. Otherwise, a reader may be believe they have 19 options and only have to pick one relay type and application to apply.

Yes
We agree with the 48-month and 72-month implementation plan for PRC-025 and R7 and R8 in PRC-023. However, we believe the implementation plan for PRC-023 as a whole is confusing. Since PRC-023-2 has a staggered implementation plan that is still has not fully been implemented, we recommend laying out a graphical timeline or a Gantt chart that compares PRC-023-2 implementation to that of PRC-023-3.
Yes
(1) We are not convinced that applicability of PRC-023 R7 and R8 to a Distribution Provider is necessary. It would be unusual for a generator that meets BES definition criteria and compliance registry criteria to be connected to a Distribution Provider. Both criteria require a single generator to be 20 MVA or a plant site to be 75 MVA. From a practical perspective, this could actually be a detriment to reliability by distracting the Distribution Provider from reliability activities because they have to focus on documenting that they do not have any applicable generators connected. How does including the Distribution Provider as an applicable entity benefit reliability? (2) The High VRFs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are inconsistent with established NERC criteria. In order to meet the High criteria, a single violation of the requirement "could directly cause or contribute to bulk electric instability, separation or a cascading sequence of failures." A single failure to have a relay set to avoid loadability concerns on a single generator could not lead to instability, separation or cascading without violating other standards. For example, TOP-004-2 R2 already require N-1 operation so a single generator tripping due to relay loadability issues would require at least two standards requirements violations. This cannot be viewed as "directly" causing. (3) We believe the VSLs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are written inconsistent FERC guideline 3 which states that the VSL cannot change the requirement. The plain language of the requirements is written in a plural format as though the requirement considers all relays are considered simultaneously. The VSLs are written such that each relay that is not set appropriately is a separate violation. The VSLs, in essence, change the requirements. For example, the Requirement for PRC-023 R7, states "shall set their load responsive relays," while the VSL essentially modifies the requirement to state "shall set each load responsive relay." We recommend modifying the VSL to be in better alignment with the requirement. (4) The wording in the second sentence of the second paragraph in PRC-023 Attachment C needs to be fixed. There seems to be an extra "Facilities." (5) RRO is used throughout both standards. It should be Regional Entity, as stated in NERC's legal memorandum on the "Use of 'Regional Reliability Organization'…" The memo states that in general, drafting teams can replace "RRO" with "RE," provided the functions being performed by the RE are related to their delegated duties. Reliability Standards that refer to REs are legally binding on the REs by operation of Rule 100 of NERC's Rules of Procedure and by the delegation agreements that NERC has entered into with each RE. (6) Please strike "other entity as specified by the Regional Reliability Organization (RRO)" that is used throughout Attachment C in PRC-023 and Attachment 1 in PRC-025. It creates compliance uncertainty and provides the Regional Entity far too much discretion. If the purpose is an attempt to document from other standards where the nameplate rating is communicating, we suggest that the drafting team perform a search of the other standards and explicitly document the entities. Otherwise, the Regional Entity, as the standard is worded, could simply decide to move the dates. FERC has ordered NERC to remove regional discretion from standards development, such as the revision of the BES definition. (7) We appreciate the relay elements that are identified for exclusion in PRC-023 Attachment C. However, we believe that the exclusion should be identified explicitly in Attachment A as well. Attachment A is referenced in applicability section. We are concerned since attachment C is not referenced in the applicability section that exclusion of the relay elements could be lost. (8) We disagree with the applicability of 3.2.5. We not understand how applicability to a distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can understand inclusion of the main GSU for a large site but not the individual collector elements.
Brett Holland
Kansas City Power and Light
same as individual info
same as individual info

No
We do not think that the Requirements added to the PRC-023-2 are any different than the Requirements in PRC-025-1. We agree that the addition of PRC-025-1 will cause the removal of part 6 of Requirement 1 in PRC-023-2.
No
We do not think that the information that is shown in the Attachment is very easy to understand but the additional information in the Guidelines and Technical Basis section helps to understand what the table is requesting. Please add to the table the examples shown in the Guidelines and Technical Basis or at a minimum refer to the location the example can be found in that document. This will assist in the understanding of the table. In the Guidelines and Technical Basis the calculation the previous value used for MW was based on the PF for Max Generation. In the new example the value of MW used changed why did that value change?
Yes
Yes
Yes
Generators and Generator step up transformers are critical elements of the BES and have very long lead times for replacement or major repair. However, the Transmission Relay load ability standard has less stringent load ability requirements than the Generator load ability standard. Transmission lines are allowed to trip at 150% of four hour rating or 115% of 15 minute rating. We do not understand the newly added portion of the Exceptions of PRC-025-1 why is there only the option of a specific curve type specified for the Generator. There is no exception available for the GSU or Aux Transformers therefore the GSU and Aux transformers that would allow them to be set like large auto transformers it is not our belief that these transformers should be required to be set with more Stringent settings. We believe that these transformers should be set similar to the large auto transformers.

Consideration of Comments

Project 2010-13.2 Phase 2 Relay Loadability: Generation

The Relay Loadability: Generation Drafting Team thanks all commenters who submitted comments on PRC-025-1 and PRC-023-3. These standards were posted for a 30-day public comment period from April 25, 2013 through May 24, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 166 different people from approximately 92 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of changes (PRC-023-3)

The generator relay loadability standard drafting team ("SDT") has revised the proposed the draft of PRC-023-3 – Transmission Relay Loadability based on stakeholder comments received during its first 30-day formal posting. The following narrative is a summary of the significant improvements made to the standard.

Standard (PRC-023-3)

The SDT, based on industry stakeholder comments, made substantive changes to the PRC-023-3 standard. The chief change was removing the previously proposed Requirement R7 and R8 which applied to the generator interconnection Facility and generator step-up transformer applicable to the Distribution Provider and Transmission Owner. With this change the SDT added the Distribution Provider and Transmission Owner to the applicability of PRC-025-1 and removed the applicability of those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from PRC-023 to establish the bright line between standards according to stakeholder comments.

- Applicability
  - Removed references to Requirements R7 and R8

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- Added the exception to sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 to exclude lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
- Removed the sections 4.2.3 and 4.2.4

- Requirements
  - Requirement R1, criterion 6 was removed to comport with the elimination of addressing load-responsive protective relays on lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
- Measures
  - Removed the proposed Requirement R7
  - Removed the proposed Requirement R8
- Compliance
  - Removed R7 and R8 references
- Violation Severity Levels
  - Removed R7 and R8
- Attachment A
  - Revised criterion 2.4 as "Note Used" since it is no longer needed
- Attachment C
  - Removed due to Requirements R7 and R8 being eliminated

Implementation Plan (PRC-023-3)

- Updated to reflect the transition of PRC-023-3 Requirement R1, Criterion 6 to the proposed PRC-025-1 criterion

VRF/VSL Justifications (PRC-023-3)

No change, not being provided for comment because the SDT is not making substantive changes to the existing requirements. Only references to Requirement R1, criterion 6 were removed

Summary of changes (PRC-025-1)

The generator relay loadability standard drafting team ("SDT") has revised the proposed draft of PRC-025-1 – Generator Relay Loadability during its 30-day formal comment posting of the standard and successive ballot which received 69.23% stakeholder approval. The following narrative is a summary of the significant improvements made to the above standard.

Standard (PRC-025-1)

- Purpose
  - Minor change for clarity
- Applicability
  - Included the Distribution Provider and Transmission Owner
  - Replaced “generator interconnection Facility” with “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant”
- Requirement
  - Added the Distribution Provider and Transmission Owner
- Measures
  - Added the Distribution Provider and Transmission Owner
- Compliance
  - Added the Distribution Provider and Transmission Owner
- Violation Severity Levels
  - Added the Distribution Provider and Transmission Owner
- Attachment 1
  - General text revisions and clarifications
  - Removed the Regional Reliability Organization (RRO) references
  - Added the following elements to Options 15, 16, and 18; “Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer”

Implementation Plan (PRC-025-1)

- The implementation period for applying settings to load-responsive protective relays that do not require replacement or removal changed from 48 months to 60 months
- The implementation period for applying settings to load-responsive protective relays that do require replacement or removal changed from 72 months to 84 months

VRF/VSL Justifications (PRC-25-1)

- Removed references to PRC-023-3.

Index to Questions, Comments, and Responses

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The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Pamela R. Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York States Reliability Council, LLC	NPCC	10
2.	Helen Lainis	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	David Thorne	Pepco Holdings Inc. & Afffiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Company	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc.	RFC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE RBB Voter Seg 1	RFC	1
2.	Larry Raczkowski (proxy for Cindy Stewart)	FE RBB Voter Seg 3	RFC	3
3.	Doug Hohlbaugh	FE RBB Voter Seg 4	RFC	4
4.	Ken Dresner	FE RBB Voter Seg 5	RFC	5
5.	Kevin Query	FE RBB Voter Seg 6	RFC	6
6.	Bill Duge	FE SME - Generation	RFC	5
7.	Brian Orians	FE SME - Generation	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

8.	Rusty Loy	FE SME - Generation	RFC	5
9.	Jim Detweiler	FE SME - Transmission	RFC	1
10.	Rich Maxwell	FE SME - Transmission	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
8.	Ken Goldsmith	ALTW	MRO	4
9.	Lee Kittleson	OTP	MRO	1, 3, 4
10.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
11.	Marie Knox	MISO	MRO	2
12.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
13.	Scott Bos	MPW	MRO	1, 3, 5, 6
14.	Scott Nickels	RPU	MRO	4
15.	Terry Harbour	MEC	MRO	1, 3, 5, 6
16.	Tom Breene	WPS	MRO	3, 4, 5, 6
17.	Tony Eddleman	NPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Bridget Coffman	Santee Cooper		
3.	Phil Winston	Southern Company		
4.	Joel Masters	SCE&G		
5.	David Greene	SERC RRO		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Patrick Brown	North American Generator Forum Standards Review Team					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NextEra Energy		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, LLC		5
4.	Pamela Dautel	IPR-GDF Suez Generation NA		5
5.	Dan Duff	Liberty Electric Power		5
6.	Mikhail Falkovich	PSEG		5
7.	Mike Hirst	Cogentrix Energy, LLC		5
8.	Gary Kruempel	MidAmerican Energy Company		5
9.	Katie Legates	American Electric Power		5
10.	Don Lock	PPL Generation, LLC		5
11.	Joe O'Brien	NIPSCO		5
12.	Dana Showalter	e.on		5
13.	William Shultz	Southern Company		5
14.	Mark Young	Tenaska, Inc.		5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Lloyd A. Linke	Western Area Power Administration	X					X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
1.	Upper Great Plains Region	Western Area Power Administrtion	MRO	1, 6										
2.	Rocky Mountain Region	Western Area Power Administrtion	WECC	1, 6										
3.	Desert Southwest Region	Western Area Power Administrtion	WECC	1, 6										
4.	Sierra Nevada Region	Western Area Power Administrtion	WECC	1, 6										
5.	CRSP Management Center	Western Area Power Administrtion	WECC	6										
10.	Group	Randi Heise	Dominion		X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	Connie Lowe	Dominion	MRO	6										
2.	Louis Slade	Dominion	RFC	5, 6										
3.	Michael Garton	Dominion	NPCC	5, 6										
4.	Michael Crowley	Dominion	SERC	1, 3										
11.	Group	Michael Lowman	Duke Energy		X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	Doug Hils		RFC	1										
2.	Lee Schuster		FRCC	3										
3.	Dale Goodwine		SERC	5										
4.	Greg Cecil		RFC	6										
12.	Group	Terry L. Blackwell	Santee Cooper		X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	Tom Abrams	Santee Cooper	SERC	1										
2.	Bridget Coffman	Santee Cooper	SERC	1										
3.	Rene' Free	Santee Cooper	SERC	1										
4.	Paul Camilletti	Santee Cooper	SERC	5										
13.	Group	Tom McElhinney	JEA		X		X		X					
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	Ted Hobson	JEA	FRCC	1										
2.	Garry Baker	JEA	FRCC	3										
3.	John Babik	JEA	FRCC	5										
14.	Group	Kent Kujala	DTE Electric				X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eizans		RFC	3, 4, 5
2.	Herring		NPCC	3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	Transmission Technical Services	WECC	1
2.	Stephen Enyeart	Customer Service Engineering	WECC	1
3.	Jim Burns	Technical Operations	WECC	1
4.	Sandra Takabayashi	Hydro Projects	WECC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Daniel McNeely		SERC	1
2.	Ann Tankesley		SERC	1
3.	Lee Thomas		SERC	5
4.	Tom Vandervort		SERC	5
5.	Paul Palmer		SERC	5
6.	Annette Dudley		SERC	5
7.	DeWayne Scott		SERC	1
8.	Ian Grant		SERC	3
9.	David Thompson		SERC	5
10.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
3.	Chris Bradley	Big Rivers Electric Corporation	SERC	
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Individual	Ed Croft	Operational Compliance	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
20.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
21.	Individual	Vladimir Stanisic	AESI Inc.										
22.	Individual	John Yale	Chelan County PUD	X				X					
23.	Individual	Barbara Kedrowski	Wisconsin Electric			X	X	X					
24.	Individual	Clem Cassmeyer	Western Farmers Electric Cooperative	X				X					
25.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
26.	Individual	NICOLE BUCKMAN	Atlantic City Electric Company			X							
27.	Individual	Mark Yerger	Potomac Electric Power Company			X							
28.	Individual	Jonathan Meyer	Idaho Power Company	X									
29.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Wryan Feil	Northeast Utilities	X									
32.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
33.	Individual	Anthony Jablonski	ReliabilityFirst										X
34.	Individual	David Jendras	Ameren	X		X		X	X				
35.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
37.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
38.	Individual	Rick Terrill	Luminant Generation					X					
39.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
40.	Individual	Mark Stein	Tri-State G&T	X		X		X					
41.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
42.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	John Bee	Exelon and its affiliates	X		X		X					
44.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
45.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
46.	Individual	Chantel Haswell	Public Service Enterprise Group	X		X		X	X				
47.	Individual	Bret Galbraith	Seminole Electric Cooperative Inc.			X	X	X	X				
48.	Individual	Russ Schneider	Flathead Electric Cooperative			X	X						
49.	Individual	Robert Rhodes	Southwest Power Pool		X								
50.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
51.	Individual	Phil Waudby	Consumers Energy			X	X	X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team thanks you for your support of other industry stakeholder comments. Approximately ten commenters supported four other organization's comments. These comments are too extensive to summarize here and are summarized in the latter questions. Groups supported include Luminant Generation Company, LLC, North American Generator Forum (i.e., Generator Forum SDT and NAGF), Pepco Holdings Inc. & Affiliates, and Western Farmers Electric Cooperative.

Organization	Agree	Supporting Comments of "Entity Name"
DTE Electric	Agree	North American Generator Forum
Wisconsin Electric	Agree	NAGF
Western Farmers Electric Cooperative	Agree	Western Farmers Electric Cooperative
Delmarva Power & Light Company	Agree	Pepco Holdings Inc. & Affiliates
Atlantic City Electric Company	Agree	Pepco Holdings Inc. and Affiliates
Potomac Electric Power Company	Agree	Pepco Holdings Inc. and Affiliates
Massachusetts Municipal Wholesale Electric Company	Agree	North American Generator Forum
Luminant Energy Company	Agree	Luminant Generation Company LLC

Organization	Agree	Supporting Comments of “Entity Name”
LLC		
Liberty Electric Power LLC	Agree	Generator Forum SDT, as submitted by Patrick Brown, Essential Power
Tennessee Valley Authority		TVA electric generators segment agrees with comments submitted by the North American Generator Forum (NAGF).

1. **Do the changes to the proposed PRC-023-2 and PRC-025-1 (listed above) provide a bright line between the two standards? If not, provide specific suggestions to improve or clarify the performance between the standards.**

Summary Consideration: Approximately three comments representing about eight entities agreed that the changes established a bright line; however, the majority comments revealed that industry stakeholders did not agree with the drafting team's proposed changes to the draft PRC-023-3 standard by adding Requirements R7 and R8 to address those load-responsive protective relays that would apply to the Distribution Provider and Transmission Owner. Among the previous additions include, Attachment C and Table 1 which contained the relay setting criteria as defined by the proposed PRC-025-1 standard applicable only to the generator. The drafting team received approximately six comments supported by 35 stakeholders that either said they did not see how the bright line was improved and the proposed Requirements R7 and R8, and Attachment C only added to confusion.

The drafting team agreed with the above comments and decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. In doing so, the generator requirements subject to PRC-023-3 have been removed; however, will be enforceable until the applicable entities become compliant with PRC-025-1, if settings need modifications. The drafting team notes that it is important to recognize that the owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025-1 and owner of load-responsive protective relays network-related Facilities in PRC-023-3 regardless of ownership of the Facilities.

The following discuss other minority comments by stakeholders. There was one comment supported by 11 entities asking the drafting team to define "generation interconnection Facilities." Although this was a minority comment, the drafting team decided this had merit because the phrase was related to the work done under the NERC Project 2009-07 – Requirements at the Generation Interface. Based on this project and industry's understanding the generator interconnection Facility is generally owned by the Generation Owner, the drafting team understood that when incorporating the Distribution Provider and Transmission Owner in PRC-025-1 that the phrase would add confusion; therefore, the drafting team developed alternative phrasing that reads: "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant."

Adding the Distribution Provider and Transmission Owner to the proposed PRC-025-1 standard addressed other minority comments. One commenter noted that the Distribution Provider, Generator Owner, and Transmission Owner should be in both standards. This was resolved addressing the majority comments. Two comments from individual entities noted that it appeared that both the generator step-up (GSU) transformer and the unit auxiliary transformer (UAT) appeared to be in both standards. After review, the drafting team noted that the GSU was applicable to the Distribution Provider and Transmission Owner in PRC-023-3 and the

Generator Owner in PRC-025-1 that own load-responsive protective relays on a GSU Facility; however, what was revealed was the lack of coverage for a UAT that might be served from the Transmission System. This identification provided support in the drafting team's decision and response to comments to remove Requirements R7 and R8 from PRC-023-3 and add the Distribution Provider and Transmission Owner to PRC-025-1 which included the UAT.

The final minority comments were related to applicability. One commenter believed that only Facilities 200 kV and above should apply to the proposed Requirements R7 and R8 in PRC-023-3. The drafting team noted that it would create a gap in the Facilities that would be covered in each standard; however, with the removal of the two proposed requirements this problem no longer exists. About three comments supported by five entities ask for items that were either already in the provided Figures or as asked for more clarity. The drafting team revised Figures 1, 2, 3, and 5 to add clarity.

An individual comment asked for clarity regarding "BES Generation Unit." The drafting team noted that the proposed PRC-025-1 standard is driven by whether or not an individual generating unit or generating plant meets the Bulk Electric System (BES) definition criteria (e.g., single units larger than 20 MVA or a site with an aggregate capacity of 75 MVA or greater). Once the unit or plant is applicable, those Elements found the Applicability section 3.2, Facilities are to be addressed by the loadability criteria of the standard. Last, one commenter asked how very small dispersed generators would be impacted. As mentioned in the previous sentence, small generators are addressed by virtue of the BES definition.

Organization	Yes or No	Question 1 Comment
Pepco Holdings Inc. & Afffiliates	No	1) The inclusion of Requirements R7 and R8 and the entire Table 1 from PRC-025-1 overly complicates PRC-023-3. In addition, inclusion of these Table 1 requirements without the corresponding Guidelines and Technical Basis document produced for PRC-025 makes the application of Table 1 in PRC-023 difficult, if not impossible. The intent of the original PRC-023 was to apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. The new PRC-025 standard should apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES generators, GSUs, UAT's and Generator Interconnection Facilities. In a good faith effort to provide a bright line between the two standards, the new PRC-023-3 standard became overly complicated and extremely confusing. It would seem that instead of adding PRC-025 requirements to PRC-023, it would be much simpler to just add Transmission Owners to the

Organization	Yes or No	Question 1 Comment
		Applicability Entities section of PRC-025. The Applicable Facilities section of each standard should identify that any load responsive relay (whether they are owned by GO's or TO's) installed on these types of facilities must comply with the respective requirements of that standard. If this were done then the original PRC-023 could be revised to exclude relays installed on generators, GSU's, UAT's and Generator Interconnection Facilities, as they will be covered by PRC-025. PRC-023 would apply solely to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. 2) It is unnecessary to remove Criterion 6 from PRC-023-3 as it represents an acceptable alternative to the methods offered in PRC-025. When load responsive relays are set on transmission line terminals connected to generation stations remote from load in accordance with Criterion 6 of PRC-023 (230% of aggregate generation nameplate capability) the resulting setting provides sufficient margin to accommodate acceptable loadability. This criterion has been successfully used for years and has gone through the full standards development process and been vetted as an acceptable alternative. Consider the example calculation for Option 14a in PRC-025. From Equation 112 the apparent primary impedance seen by the relay on the high side of the GSU is 74.3 ohms primary at an angle of 52.77 degrees. Now assume the 230% method from PRC-023 Criterion 6 was used instead. The new apparent power would be 2.3 x (767.6 MW + j 475.6 MVAR) = 2.3 x 903 MVA =2076.9 MVA at an angle of 31.8 degrees. Using Equation 112 the apparent primary impedance would be 41.4 ohms at 31.8 degrees. From Equation 115 the setting required to satisfy Option 14a criteria from PRC-025 would be 15.283 ohms sec = 76.42 ohms primary at 85 degrees. The reach of this relay along the 31.8 degree load angle would be 76.42 x Cos (85 - 31.8) = 45.77 ohms primary. Since this is greater than the 41.4 ohm setting resulting from Criterion 6 of PRC-023, the PRC-023 Criterion is slightly more conservative, requiring a slightly smaller relay reach than Option 14a. As such, both methods should be considered equally effective in ensuring relay loadability.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made. The drafting team thanks you for your comment and notes that it considered this same concern in past meetings and concluded that the Mega-Watt (MW) value reported to the Transmission Planner was the most practical approach for a basis in determining the required setting(s). The Generator Owner has flexibility in using a more restrictive setting, which would be the case of using the generator name plate. In option 1, for example, the requirement is to use 100% of the reported MW and 150% of the nameplate MW to arrive at the Mvar component of the complex power. The impedance element must be set less than the calculated impedance derived from 115% of the complex power, which is using criteria (1) and (2). The standard allows the applicable entities the flexibility to account for variable changes in the reported MW value and select a setting that best suits their specific operating history or expectation. No change made. Using the reported MW value accounts for environmental conditions that impact the operation of generation units and those units which operate at a level lower than their nameplate rating. This more closely achieves a loadability setting corresponding with the expected performance of the generator during field-forcing. No change made.		
FirstEnergy	No	FirstEnergy (FE) appreciates the attempt to develop a bright-line method but feel the approach taken is over complicating the standards. FE believes that the changes made to PRC-023 with the inclusion of requirements R7 and R8 and the associated Attachment C cause unnecessary confusion. FE proposes that the team remove R7, R8 and Attachment C from PRC-023 and retain a modified version of PRC-023, R1 item 6. Further, as supported in our comments below, we encourage the team to limit the applicability of PRC-023 to the TO and DP and the applicability of PRC-025 to the GO. FE

Organization	Yes or No	Question 1 Comment
		believes it is imperative for NERC to develop its standards in a consistent approach in regard to terminology that is deemed “transmission” and those deemed “generation”. We are concerned that the proposed changes to PRC-023 and PRC-025 overly complicate what most in industry already understand to be “transmission” and “generation” facilities. For example, NERC recently proposed errata changes to PRC-004 and PRC-005 to clarify that for a GO the requirements of those standards extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facility. It’s difficult to understand why PRC-004 and PRC-005 seem to have clear TO and GO boundaries when it comes to reporting relay misoperations and performing relay maintenance, yet when ensuring relay loadability requirements are met things all of a sudden become much more complicated. To date, generation interconnection facility(ies) as used in NERC standards are generator owner assets, “generator lead”, operated at transmission voltage levels. However, if the generator lead happens to be owned by a transmission owner, then it’s understood simply to be a transmission line or transmission facility. The two relay loadability standards should maintain this same simplicity and PRC-023 should apply only to TO/DP and PRC-025 to the GO. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change

Organization	Yes or No	Question 1 Comment
		made. The Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. We suggest that the team take this opportunity to introduce a formally defined NERC Glossary Term for generator interconnection facility. During the recent webinar the team spent a fair amount of time indicating that when evaluating a generator interconnection facility(ies) as shown in Figure 1 and Figure 2 that it essentially comes down to the relay owner when determining which standard (PRC-023 or PRC-025) is applicable. The team indicated that if the GO owns the relay for line breaker(s) at Bus A then PRC-025 applies, but if the DP/TO owns the relay then PRC-023 applies. The team further described that the GO was left in PRC-023 to handle a situation where they may own relaying for line breaker(s) on networked transmission lines as shown in Figure 3. **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made. The team also cited they retained the GO for this situation to avoid a potential “registration tension”. The perceived need for the GO in standard PRC-023 calls into question the facility rating for the network transmission line as established under FAC-008-3. NERC standards must maintain consistent philosophies in terminology throughout all standards and cover the most common system configurations. Any unique situations will need to be dealt with on a case by case basis between asset owners. Additionally, NERC drafting teams should not be writing standards to cover

Organization	Yes or No	Question 1 Comment
		one-off configurations simply to address potential entity registration concerns. **Response:** The drafting team found that these conditions exist throughout North America in varying degrees due to industry deregulation and other factors. The drafting team is defining criteria such that similar Facilities will be subject to similar requirements regardless of Facility ownership as it relates to the NERC functional model. No change made. While FE strongly objects to the use of R7, R8 and Attachment C in PRC-023, if the team does not agree with our proposal to remove the GO completely from PRC-023 then as an alternate approach we support comments filed by Pepco Holdings, Inc. - PHI which suggesting adding the TO/DP to PRC-025 and removing R7, R8 and Attachment C from PRC-023. Either approach (FE's or PHI's) requires retaining item 6 of R1 in PRC-023. **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made. The Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. The criterion in PRC-025-1 is technically similar, but more precise than PRC-023-2 Requirement R1, Criterion 6; therefore, Criterion 6 must be removed. The drafting team acknowledges that entities that previously implemented Criterion 6 may find that changes are necessary; if so, the PRC-025-1 Implementation Plan would apply. Change

Organization	Yes or No	Question 1 Comment
		made. In summary, for PRC-023, FE proposes the following: 1.) Remove the Generator Owner applicability 2.) Remove Requirements 7 and 8 since they will be included in PRC-025 3.) Remove Attachment C 4.) Change Requirement 1 Criteria #6 to read as follows: “Set transmission line relays applied on transmission lines connected to generation stations remote to load directional towards the generator so they do not operate at or below 115% of the rating of the generator as calculated according to applicable NERC standards.” Although not our preferred option, we also recommend the team considered the suggestion by PHI that would add the TO as an applicable entity to PRC-025 while also removing PRC-023 R7, R8 and Attachment C. **Response:** Thank you for adding the summary. Please see the above responses.
Response: The drafting team thanks you for your comments; please see the above responses.		
DTE Electric	No	Comments: The distinction is not clear between these two standards regarding generator owner relays that look toward the transmission system. Perhaps specifying the application location of the relay (CT and PT inputs) would help in clarifying the differences
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines		

Organization	Yes or No	Question 1 Comment
and Technical Basis for further information on applications. Change made.		
Bonneville Power Administration	No	The requirements for generator interconnection facilities in PRC-023-3 apply to Transmission Owner's (and Distribution Provider's, and the requirements for generator interconnection facilities in PRC-025-1 apply to Generation Owner's. BPA believes that putting requirements for the generator interconnection facilities in two separate standards and making the applicability of the standards different is confusing and unnecessary. BPA recommends that all interconnection facilities, regardless of ownership, should be covered within one standard to provide uniformity in the application of settings for interconnection facilities.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
ACES Standards Collaborators	No	There is definitely much clearer delineation between what is required in PRC-023 by the Transmission Owner and Distribution Provider and in PRC-025 by the Generation Owner for generator step up transformers, generators, auxiliary transformers and generator interconnection facilities. However, PRC-023 still has other requirements that are applicable to Generators Owners that do not make sense, create compliance risks and, thus, detract from reliability by distracting the Generator Owner from value added reliability activities. For example, PRC-023 R1 is still applicable to the Generation Owner and it should not be. A Generation Owner does not own transmission beyond the generator interconnection facility. This is recognized in Project 2010-07 Generator Requirements at the Transmission Interface and NERC's work surrounding the GO/TO and GOP/TOP registration issues. If a Generator Owner owned transmission beyond the generator

Organization	Yes or No	Question 1 Comment
		interconnection facility, they would be registered as a Transmission Owner. Thus, the Generator Owner will be stuck essentially going through a registration exercise for every compliance activity to prove that the requirements do not apply because they do not own transmission facilities. Other requirements in PRC-023 that require removal of Generator Owner include R2, R3, R4, and R5. Until these removals occur, we will not be able to support the standard.
Response: The drafting team thanks you for your comment and notes that the Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made.		
Chelan County PUD	No	It seems that GSU and UAT would be subject to PRC-023 and PRC-025. It would be cleaner if one standard applied to GSU and UAT and the other to the transmission circuits.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. With the changes, the GSU and UAT now apply to one standard, the proposed PRC-025-1.		
Western Farmers Electric Cooperative	No	See comments to question 5
Response: The drafting team thanks you for your comments; please see responses in question 5.		

Organization	Yes or No	Question 1 Comment
Ameren	No	(1) For consistency, we believe that PRC-023-3 requirement R7 should only apply at 200kV and above. Therefore, we request the SDT to change 4.2.3.1 to 'Transmission lines operated at 200kV and above that are used..."
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. Although PRC-023 has a provision for addressing Facilities less than 200 kV for transmission network load-responsive protective relays; however, the drafting team is addressing generation Facilities such that the PRC-025 standard will be consistent with the definition of the Bulk Electric System (BES). Including those generation Facilities that are less than 200 kV addresses all BES generation which may be important during an event where field-forcing increases the need for a reasonable level of loadability. No change made.		
American Electric Power	No	AEP believes that both documents would benefit from the inclusion of a simplified GO/TO interface diagram showing the overlap and applicability of the two standards within the opening section of each standard. Clarity needs to be provided to PRC-023-3 regarding the proper consideration of GO-owned transmission line protection systems. It must be understood that for load responsive relays subject to R7 and R8, the responsibility to perform loadability evaluations is on whoever is the owner of the Protection System. Regarding PRC-023-3, it is unclear exactly what facilities are included in the term “BES Generating Unit”. It is requested that this be clarified. AEP also requests clarification on the voltage levels applicable to Regarding PRC-023-3 R7. Section 4.2.3.1 currently applies to “transmission lines” which implies that all voltage levels would be subject to this requirement. It is requested that this be revised to clarify exactly what voltage applies.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and notes that the Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. The circumstance is the same as the current definition of Bulk Electric System that apply to the those individual generating units 20 MVA and larger or 75 MVA in aggregate on a site, including those Blackstart generating units identified in the Transmission Operator's system restoration plan. No change made. The drafting team notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made. With the removal of Requirements R7 and R8, the Applicability section 4.2.3.1 is no longer relevant. Change made.		
Luminant Generation	No	Luminant recommends the following: (1) Load responsive relays identified in PRC-025-1 and 023-3 connected on generator breaker(s) at the GSU high side and are primarily used for backup of failed transmission line relaying shall use options in Attachment C (PRC-023-3) and Attachment 1 (PRC-025-1). (2) Load responsive relays identified in PRC-023-3 and connected on the high side of the GSU that are primarily used for transmission line protection shall use the existing criteria in PRC-023-2, Requirements R1 through R6. The above recommendations can be done by adding diagrams in PRC-023-3 and clarifying Figures 1, 2, and 3 in PRC-025-1.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. No change made.		
Ingleside Cogeneration LP	No	Even though the language in both standards draws a technically accurate bright line, Ingleside Cogeneration believes that the addition of the generator relay criteria to PRC-023-3 is confusing at best. It appears that the issue has to do with the ownership of the relays. In some cases the DP and/or the TO owns a load responsive relay that is protecting generation equipment. Conversely, some GOs own load responsive relays that protect transmission equipment. If the concept of the two standards is that PRC-023-3 applies to transmission-related relays and PRC-025-1 applies to generation-related relays, than the owner of the relay is not a gating factor. This means that the applicability table for both standards would include DPs, GOs, and TOs. There would be no repeated criteria between the standards in this arrangement - and less confusing in our view.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group	No	For UATs per PRC-025-1, that are energized from the system (as opposed to from the GSU), the SDT seems to assumes that no TO or DP owns the load responsive relays for these UATs. Has that been verified by the SDT?
Response: The drafting team thanks you for your comment and notes it has not independently verified this particular scenario; however, with the proposed revisions, the Distribution Provider and Transmission Owner that own load-responsive protective relays regarding the unit auxiliary transformer (UAT) are now applicable under the proposed PRC-025-1 standard. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Flathead Electric Cooperative	No	it is not clear to me how this would impact very small dispersed generators.
Response: The drafting thanks you for your comments. This would not have any impact on very small dispersed generators unless they form aggregated generation at a single interconnection point as delineated in the latest approved BES definition (i.e., those individual generating units 20 MVA and larger or 75 MVA in aggregate on a site). No change made.		
Kansas City Power and Light	No	We do not think that the Requirements added to the PRC-023-2 are any different than the Requirements in PRC-025-1. We agree that the addition of PRC-025-1 will cause the removal of part 6 of Requirement 1 in PRC-023-2.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines		

Organization	Yes or No	Question 1 Comment
that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made.		
Liberty Electric Power LLC	No	
Dominion	Yes	Dominion agrees that the addition of requirements in PRC-023-3, R7 and R8 strengthens the bright line between the two standards. However, we do not agree with use of the term “Transmission’ in 4.2.3.1 as it is our position that it does not conform with the intent of the term as defined in the NERC Glossary of Terms. We therefore suggest the sentence be revised to read “Lines that are used solely to export energy directly from a BES generating unit or generating plant to the network.”
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Operational Compliance	Yes	Content is good. However - the two standards should refer to EXACTLY the same table of Relay Loadability Evaluation Criteria with EXACTLY the SAME OPTION #s for each Relay Type/Application. The table could stand on its own and each record be labeled with PRC-025 and/or PRC-023 applicability (new column(s)).
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive		

Organization	Yes or No	Question 1 Comment
protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
PPL NERC Registered Affiliates	Yes	
Western Area Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
PacifiCorp	Yes	
AESI Inc.	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Entergy Services, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
(Transmission)		
Southwest Power Pool	Yes	

2. Does the Table 1: Relay Loadability Evaluation Criteria in both PRC-023-3 (Attachment C) and PRC-025-1 (Attachment 1) clearly identify the criteria for setting load-responsive protective relays? If not, provide specific detail that would improve the clarity of Table 1.

Summary Consideration: In whole, the comments presented in this question were minority comments. Approximately, two comments representing 16 stakeholders reiterated that Requirements R7 and R8 should be removed from PRC-023. The drafting team removed the requirements and instead added the Distribution Provider and Transmission Owner to PRC-025 to avoid a gap or overlap in compliance as addresses in the above question.

The most notable minority comment by the SERC Protection Control Subcommittee identified key elements missing in PRC-025-1 that were addressed in PRC-023. That item was “Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.” The drafting team agreed and added these elements to the proposed PRC-025-1, Attachment 1, Table 1.

Also, one entity objected to the use of “Regional Reliability Organization (RRO)” within the two standards due to being outdated. The drafting team re-evaluated the use of the term which was added to address an implementation gap between the MOD-025-2 standard that is pending regulatory approval and the subsequent approval of PRC-025-1. The problem stemmed from the applicable entities possibly not having an official reported value to the Transmission Planner pursuant to MOD-025-1 which could pose a compliance risk. To resolve this issue, the drafting team agreed with support of comments and regulatory staff to increase the PRC-025-1 standard Implementation Plan by one year. This would ensure that MOD-025-1 would be fully in effect (about 6 months) upon the date which entities must demonstrate compliance with PRC-025-1.

One entity suggested to the drafting team to provide references within the PRC-025-1, Table to improve the clarity. Previously, the drafting team in Table 1 and in options addressing the generator-side relay of the GSU, referenced the high-side option to help direct readers to the corresponding option. The drafting team clarified the high-side options with the same reference back to the generator-side relay of the GSU. The remaining comments, all minority comments, related to technical issues the drafting team worked through in earlier postings. Items such as using the generator nameplate, seasonal variation, or items addressed more fully in other questions in this comment report.

Organization	Yes or No	Question 2 Comment
Pepco Holdings Inc. & Afffiliates	No	For the PRC-025 standard the inclusion of Table 1 along with the Figures and Example Calculations in the Guidelines and Technical Basis document clearly identifies the proposed setting criteria. However, the inclusion of Table 1 in PRC-023 overly complicates the scope of PRC-023, and without inclusion of the corresponding Guidelines and Technical Basis document makes application of Table 1 criteria difficult. We feel strongly that all references to load responsive relays applied on generators, GSU's, UAT's and Generation Interconnection Facilities (including Table 1 and Requirements R7 and R8) should be eliminated from PRC-023 as they are already adequately covered in PRC-025. Transmission Owners that own load responsive relays on those types of facilities should be included as an Applicable Entity under PRC-025. (See comments submitted for Question 1).
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made.		
FirstEnergy	No	As stated above (Question 1) FE does not support the inclusion of Attachment C in PRC-023. See question 1 for more information. From a technical standpoint, we support Table 1 of PRC-025.
Response: The drafting team thanks you for your comments; please see the above responses in question 1.		
SERC Protection and Controls Subcommittee	No	There is a discrepancy between the relay functions listed in PRC-023-3 Attachment A and those identified in PRC-023-3 Attachment C Table 1 and PRC-025-1 Attachment 1 Table 1. PRC-023-3 Attachment A includes under 1.6, "Phase overcurrent supervisory

Organization	Yes or No	Question 2 Comment
		elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." These schemes are not accounted for in the Table 1 of either proposed standard. Given these schemes are required to meet loadability criteria on transmission lines not meeting the "generator interconnection facility" designation (i.e. networked lines), the exclusion of the schemes from generator loadability criteria creates confusion. Loadability criteria should be included for "Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications" in Table 1 of both PRC-023-3 and PRC-025-1.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. The drafting team thanks you for your comments and agrees with this suggestion and has modified the proposed PRC-025-1 standard in Attachment 1, Table 1, Options 15a, 15b, 16a, 16b, 18 and 19 to address this condition. Change made.		
Dominion	No	Dominion believes that the appropriate designation of "Real Power output" is the generator nameplate rating however Dominion does recognize that the addition of "gross" prior to MW is an improvement to the table wording.
Response: The drafting team thanks you for your comment and notes that it considered this same concern in past meetings and concluded that the Mega-Watt (MW) value reported to the Transmission Planner was the most practical approach for a basis in		

Organization	Yes or No	Question 2 Comment
determining the required setting(s). The Generator Owner has flexibility in using a more restrictive setting, which would be the case of using the generator name plate. In option 1, for example, the requirement is to use 100% of the reported MW and 150% of the nameplate MW to arrive at the Mvar component of the complex power. The impedance element must be set less than the calculated impedance derived from 115% of the complex power, which is using criteria (1) and (2). The standard allows the applicable entities the flexibility to account for variable changes in the reported MW value and select a setting that best suits their specific operating history or expectation. No change made. Using the reported MW value accounts for environmental conditions that impact the operation of generation units and those units which operate at a level lower than their nameplate rating. This more closely achieves a loadability setting corresponding with the expected performance of the generator during field-forcing. No change made.		
Bonneville Power Administration	No	Example: A 230kV line that is connected between a substation Terminal and a Generating station. (Comment 1) This circuit fits under 4.2.3 of PRC-023-3, so it is subject to Requirement 7. The circuit also fits under 4.2.1, so it is subject to Requirements R1 throughR5. BPA believes it should only be subject to R1 through R5 or R7, not both. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Applicability – 4.2, Circuits now provide the exclusion “except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.” Criterion 6 in Requirement R1 remains unused. Change made.

Organization	Yes or No	Question 2 Comment
		In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. (Comment 2) R7 requires that the load responsive relays be set in accordance with PRC-023-3, Attachment C. BPA would like to point out that the phase distance relays at the substation terminal looking toward the generation are not covered by Attachment C and believes this creates a problem as it makes it impossible for these relays to be set in accordance with Attachment C. The same problem also exists for relays at the terminal of the generator step up (GSU) transformer looking toward the generation, recognizing that this is not a normal application. Based on these issues, BPA believes Attachment C should address all relays, not just those looking towards the Transmission system. **Response:** The drafting team added text to note that load-responsive protective relays directional toward the generator are not included. Also, the drafting team notes that the load-responsive protective relays directional toward the generator are not challenged by the loadability concerns for the stressed system conditions being addressed by the proposed PRC-025-1 standard; thus, criteria for these relays are not necessary. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Texas Reliability Entity	No	(1) Texas RE objects to the use of the term Regional Reliability Organization (RRO) in Table 1. RRO is an obsolete term that NERC had been trying to purge from the standards, and we are somewhat alarmed to see it used in a new place in the standards. While we recognize that RRO is defined in the Glossary, it is not in the functional model and, at least in our region, it does not identify any entity and it is ambiguous. We urge you to replace the term RRO with an entity type from the functional model, or to write a description of what is intended without using the term

Organization	Yes or No	Question 2 Comment
		"RRO". **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made. (2) Regarding the "Transformers" section on page 7 and footnote 3 on page 10, consider whether it is appropriate to use the "nameplate impedance at the nominal GSU turns ratio" in all instances. In some cases, it is more appropriate to use the calculated (i.e. with compensation) impedance that reflects the lowest value based on the de-energized tap and LTC tap positions for this purpose. **Response:** The drafting team notes that the tap impedance for older transformers may not be available for all tap positions; therefore, the drafting team is requiring the use of the nominal impedance. If entities wish to employ the actual tap impedance used or the most conservative tap impedance available, they may reflect that in the relay settings selected provided that the setting achieves the relay pick up setting criteria in Table 1. No change made. (3) For Options 1a, 2a, and 7a, consider using 0.9 per unit instead of 0.95 per unit, because typical disturbance (post-contingency) voltage criterion is 0.9 p.u. **Response:** The 0.95 per unit voltage specified in these options reflect the approximate generator bus voltage at a 0.85 per unit system voltage with a representative transformer impedance of 12 percent during field-forcing. No change made. (4) Consider clarifying that the Real Power output criteria should be based on the [highest seasonal] MW rating for the applicable unit. There can be significant seasonal variations in MW capabilities for some units. We don't expect pickup settings to be changed from season to season, so an appropriate year-round setting should be determined and applied. **Response:** Seasonal variations are discussed in Attachment 1: Relay Settings under the heading "Generators." The section states: "If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard." No

Organization	Yes or No	Question 2 Comment
		change made. (5) Some transmission systems have steady state stability limits that encroach into the generator capability limits. Consider adding exclusion criteria for these types of scenarios. **Response:** The drafting team notes that the generator is providing VARs to the system during field-forcing anticipated by the standard. The steady-state stability limit encroachment occurs only in the leading VAR scenario. This issue is being addressed by the NERC Board of Trustees adopted PRC-019-1 standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
AESI Inc.	No	The team is commended for an extensive effort to provide high level of detail through numerous relay setting examples summarized in Table 1 and elaborated in the document PRC_025_1_Guidlines_and_Technical_Basis_Draft_3_2013_04_24_Redline.pdf. Nonetheless, the following points may need further attention: 1. The settings derived by simulations versus the settings derived by manual calculations are noticeably different, the latter being repeatedly much more conservative (e.g. 8c: 6.6 A pu versus 8a: 9.5 A pu), exposing generators to a higher risk of overloading. It would be expected that the results of manual calculations and simulations would yield closer values, at least for most of typical configurations. It appears that underlying assumptions used in the calculations and simulations may need to be fine-tuned. For example, is it realistic to have field forcing producing 1.5 pu MVAR output and at the same time generator bus voltage at 0.95 pu. **Response:** The drafting team notes that “manual” calculations, in some cases, may be significantly more conservative than simulation results. However, the criteria specified by Options 1a, etc. reflect behavior observed for some generators in actual events and simulations. Therefore, the specified criteria are appropriate for non-simulation based

Organization	Yes or No	Question 2 Comment
		analysis. No change made. 2. The settings derived by manual calculations are such the generators are exposed to a higher risk of overloading: • Example 1a - 21 protection would operate only when unit loading exceeds approx. 280% (at rated power factor). • Example 2a - 51V protection pickup is set at equivalent of approx. 170% loading. Taking into account that overcurrent relays actually react when current exceeds 1.5 pickup setting, equivalent loading on the unit would have to exceed 250% before timing is initiated. Depending on the relay characteristic, time delay can be significant. **Response:** The drafting team acknowledges that fault protective relaying may not provide adequate thermal overload protection; an exclusion is provided in the proposed PRC-025-1 standard for protection that is focused exclusively on overload protection. No change made. 3. C37.102 states that acceptable settings for 21 function are 150% to 200% (at rated power factor). These values should guide the requirements of this standard. **Response:** The drafting team notes that for some generators a setting of 150% to 200% of the generator MVA rating at its rated power factor is insufficient and is moving beyond the general application guidance expressed in C37.102 so that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. The drafting team also notes that while C37.102 provides general guidance on the reach for phase fault backup protection, it also provides insight regarding situations in which voltage regulator action could cause an incorrect trip. Similar to information in the Guidelines and Technical Basis for PRC-025-1, C37.102 notes that consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective

Organization	Yes or No	Question 2 Comment
		devices in the voltage regulator. It also recommends that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine generator, and that stability studies may be needed to help determine a set point to optimize protection and coordination. No change made. 4. The Table specifies pickup setting criteria. It remains unclear when are the relays allowed to trip. **Response:** The drafting team notes that the impedance elements are allowed to trip at less than the pickup setting criteria and overcurrent elements are allowed to trip at greater than the pickup setting criteria. Timing considerations such as relay coordination are not addressed by this standard. No change made. 5. Examples 7a, b, c, seem to be duplication of 1a, b, c. **Response:** Refer to Figure 4 in the Guidelines and Technical Basis. Option 1 relays are located on the generator and Option 7 relays are on the low-side terminals of the generator step-up (GSU) transformer. No change made. 6. The following comment from the Guidelines document is not clear:======Options 7a and 10, Table 1 - Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator busvoltage, ***however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (Vgen)***?:========== **Response:** The description prior to Equation 76 in the Guidelines and Technical Basis has been clarified as to why the 0.95 voltage is being used in the case of mixed synchronous and asynchronous generation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Xcel Energy	No	For 51 relay that is installed on the high side of GSU, we suggest it should be an acceptable option if the 51 relay setting meets R1 Criteria 11.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comments notes that the criteria expressed in PRC-023-3, R1 Criterion 11, represents steady-state conditions for transmission transformers and does not represent the conditions that the GSU would see during field-forcing conditions. No change made.		
Ameren	No	(1) We ask the SDT to clarify that 'nameplate MVA rating' means the 'generator nameplate MVA rating'. Therefore we request that the SDT either add a statement "Unless otherwise stated, 'nameplate MVA rating' means the 'generator nameplate MVA rating' throughout Table 1", or insert 'generator' before 'nameplate MVA rating'.
Response: The drafting team thanks you for your comments and has added "generator" immediately prior to the applicable uses of "nameplate MVA rating" in Table 1. Change made.		
American Electric Power	No	PRC-023-3 must be clear in stating that, if a Transmission or Distribution line used solely to export energy directly from the GU has its own circuit breaker, then the existing R1 through R5 criteria should be applied based on the rating of the line. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Applicability – 4.2, Circuits now provide the exclusion "except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network." Criterion 6 in Requirement R1 remains unused. Change made. PRC-023-3 appears to exclude relays directional toward the Generating Unit. For example, if you attempt to evaluate loadability for two-terminal 345kV line to a

Organization	Yes or No	Question 2 Comment
		windfarm, it appears to be applicable to both PRC-023-3 4.2.1 and 4.2.3. This would make it difficult to determine what Transmission lines are subject to evaluation and which requirement to apply, R1 or R7. Based on the current draft, it is not clear what criteria set to apply. The criteria in Table 1 is based on Generator's power while the criteria in Requirement 1 is based on circuit ratings. It needs to be clarified which criteria set is to be applied. A second example is in a situation when a loadability evaluation is needed for a two-terminal line that is definitely not applicable to 4.2.1., but *is* applicable to 4.2.3. The intent of having two standards appears to be to have the relays on the Generating Unit end owned by the GO, set according to criteria R1 in PRC-025-1; and to have the relays on Generating Unit end owned by the TO, set according to criteria R7 in PRC-023-3. In this example, there would appear to be no criteria required to set relays on the end external to the Generating Unit, for relays owned by either the GO or TO. Clarification is needed to define responsibility based on Protection System ownership as well as to clearly convey the applicability of remote protection systems. **Response:** The drafting team added text to note that load-responsive protective relays directional toward the generator are not included. Also, the drafting team notes that the load-responsive protective relays directional toward the generator are not challenged by the loadability concerns for the stressed system conditions being addressed by the proposed PRC-025-1 standard; thus, criteria for these relays are not necessary. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Luminant disagrees that the criterion for setting load responsive relays is clear because of the bright line is vague. Luminant recommends that each standard be clear in addressing the relay setting criteria by its primary application.
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on		

Organization	Yes or No	Question 2 Comment
"Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
Kansas City Power and Light	No	We do not think that the information that is shown in the Attachment is very easy to understand but the additional information in the Guidelines and Technical Basis section helps to understand what the table is requesting. Please add to the table the examples shown in the Guidelines and Technical Basis or at a minimum refer to the location the example can be found in that document. This will assist in the understanding of the table. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. In the Guidelines and Technical Basis the calculation the previous value used for MW was based on the PF for Max Generation. In the new example the value of MW used

Organization	Yes or No	Question 2 Comment
		changed why did that value change? **Response:** In the previous draft of the calculations, the $P_{reported}$ and the calculated P happened to be the same value and caused confusion. Because of the identical values, the drafting team decided to use a different value for $P_{reported}$ so that the values would not be confused. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Western Area Power Administration	Yes	Recommend adding reference to Table 1 - Options 7, 8, 9, 10, 11, 12 - Relay Type back to options 1, 2, 3, 4, 5, 6 for applications on the generator side of the GSU. The language and reference used in the Relay Type column for Options 1-6 added clarity and should be mirrored in Options 7-12.
Response: The drafting team thanks you for your comment and agrees that where the generator-side options refer to the high-side options, that the high-side options should also refer to the generator-side options. Change made.		
ACES Standards Collaborators	Yes	The table is much clearer than in past versions. However, we do recommend one minor additional change. The option numbers should be reset to 1 for every application and relay type combination since they are truly options within those combinations. Otherwise, a reader may be believe they have 19 options and only have to pick one relay type and application to apply.
Response: The drafting team thanks you for your comment and suggestion; however, the drafting team asserts the use of sequential numbering is more beneficial and avoids confusion when referring to an option. No change made.		
Operational Compliance	Yes	But...see comments for Question #1.
Response: The drafting team thanks you for your comments; please see the above responses for question 1.		

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	(1) Manitoba Hydro suggests eliminating Table 1 from one of the standards and referencing it in the other standard, since both PRC-023-3 and PRC-025-1 are already very lengthy standards.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered	Yes	

Organization	Yes or No	Question 2 Comment
Affiliates		
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
PacifiCorp	Yes	
Chelan County PUD	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
ReliabilityFirst	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Ingleside Cogeneration LP	Yes	
Entergy Services, Inc. (Transmission)	Yes	

Organization	Yes or No	Question 2 Comment
Southwest Power Pool	Yes	

3. **Does PRC-025-1, Guidelines and Technical Basis provide a clear understanding of the various criteria, including the options (e.g., 1a, 1b, 1c, 2a, etc.) for setting load-responsive protective relays? If not, provide specific detail that would improve the Guidelines and Technical Basis.**

Summary Consideration: There were three significant comments in this question. One comment representing about five stakeholders suggested defining “generator interconnection Facility.” The drafting team addressed this in several comments and the summary can be found in the summary to question 1. Second, the same comment revealed minor errors in a Figure, calculation, and within the Guidelines and Technical Basis. The drafting team corrected these errors and made clarifications. Also, this commenter suggested performing calculations in per unit; however, the team disagreed that the current method was adequate.

Other minority single comments relate to issues the drafting team has worked through in earlier postings of the standard. They include the basis why transformers are being addressed, applicability of the UAT used only during startup, multi-winding example calculation, changes in the reported Real Power out to the Transmission Planner (e.g. seasonal variations), appending the Guidelines and Technical Basis back to the standard, and request for clarity in the examples.

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Afffiliates	No	1) The new term “Generator Interconnection Facilities” is not defined in the NERC Glossary of terms, nor is it defined in the body of the standard. It is defined in the Guidelines and Technical Basis document; however, we feel this term needs to be defined within the body of the standard itself. Perhaps a footnote similar to that used to define Unit Auxiliary Transformers would be appropriate. We would suggest the same definition used in the Guidelines and Technical Basis document be inserted: “Generator interconnection Facility(ies) consists of Elements between the generator step-up transformer and the interface with the portion of the bulk Electric System (BES) where Transmission Owners take over the ownership.” **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.

Organization	Yes or No	Question 3 Comment
		2) In Figures 4 and 5 the CT's supplying the 21, 51V-R and 51V-C relays connected to the generator(s) look like they are connected to the generator neutral. To make it clear that they are supplied from CT's connected in the phase leads, a phase to neutral transition symbol (ref Fig 7.4 in IEEE C37.102) should be used to indicate the CTs are located above the neutral connection point. **Response:** Figures 4 and 5 have been modified to address this concern. Change made. 3) In Figure 5 there is a 51 relay shown connected to the 22kV bus leads supplying the generator on the left hand side of the drawing. This 51 relay is not reverenced, or used, in any of the options and therefore should be removed from the drawing. **Response:** Figure 5 and Table 1, Option 5 has been revised to address this concern. Change made. 4) Options 14a, 14b, 15a, 15b, 16a and 16b all use an MVAR value equal to 120% of the aggregate generation MW value, instead of the 150% value used when the relays are located on the generator side of the GSU transformer. Presumably this is to account for the I squared Xt MVAR loss consumed in the GSU transformer. However, there is no mention of this fact in the Guidelines and Technical Basis document. To avoid confusion as to why different MVAR criteria are used, supporting technical justification / explanation should be offered in the document. **Response:** The assumption is correct. Discussion has been added to the Guidelines and Technical Basis. Change made. 5) The example calculations for Options 4 and 10 are combined as a single identical set of calculations. This calculation is appropriate for Option 10 but not for Option 4. Referring to Figure 5, the 21 relays for Option 4 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 21 relay on each individual generator (Option 4) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. A separate

Organization	Yes or No	Question 3 Comment
		calculation for Option 4 should be developed. For that Option 4 case the single generator apparent power (assuming three generators of equal size) would be 102/3 = 34 MW and 63.2/3 = 21 MVAR, which is 40 MVA for each generator. **Response:** Figure 5 in the Guidelines and Technical Basis has been modified to account for this discrepancy and the calculation example for Option 4 and 10 have been separated. Change made. 6) The example calculations for Option 5 appear to be incorrect. Again referring to Figure 5, the 51V-R relays for Option 5 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 51V-R relay on each individual generator (Option 5) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. As such the 51V-R relay should be set to 130% of the maximum MVA rating of that individual generator. Again assuming three units of equal size, each generator would be rated 40MVA and therefore the 51V-R relay should be set to not operate below 1.3 x 40 = 52 MVA **Response:** The calculation for Option 5 in the Guidelines and Technical Basis has been corrected to reflect a single asynchronous generation unit and not the aggregate. Change made. 7) The example calculations for Options 7a, 10, 8a, 9a, 11, and 12 illustrate a mixture of synchronous and asynchronous generators. However, there is no corresponding one-line drawing which corresponds to these examples. Because of this, it is difficult visualize the topology of this arrangement and where the corresponding relays would be located. If the SDT wishes to provide an example calculation where there is a mix of synchronous and asynchronous generation then we would suggest an additional figure be added (Figure 6) which would illustrate this type of connection. **Response:** Figure 5 and the calculations for Option 10 in the Guidelines and Technical Basis has been modified and corrected to reflect a mixture of synchronous and

Organization	Yes or No	Question 3 Comment
		asynchronous generators (Equations 71-93). Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
PPL NERC Registered Affiliates	No	See Comments for Question #5
Response: The drafting team thanks you for your comments; please see the responses for question 5.		
North American Generator Forum Standards Review Team	No	See comments to question 5 below
Response: The drafting team thanks you for your comments; please see the responses for question 5.		
Duke Energy	No	Examples of calculations are helpful. However, more details on the root of the calculations are needed. Exclusively calculating values on a per unit basis would add more clarity.
Response: The drafting team thanks you for your comment and asserts the basis for the calculations are addressed in the Guidelines and Technical Basis narrative. The drafting team also notes that Generator Owners may perform calculations in per unit or in actual values. The examples are provided in actual values. No change made.		
JEA	No	While it has been demonstrated in the 2003 blackout that a small percentage of generating units did trip off line prematurely due to conservative setting of generator protection systems, no evidence has been provided that transformer tripping contributed to the cause of the generation outages. The sole purpose as stated by the SDT for including transformers is a directive from FERC. We believe that there should be some evidence as to the benefit of preforming protection modifications to

Organization	Yes or No	Question 3 Comment
		transformers and that they should not simply be included until a study can be performed to show the cost benefit analysis and therefore recommend that transformers be excluded during this phase and be incorporated into a phase III. **Response:** FERC has already ruled on entities' requests for clarification and rehearing on Order 733 with regard to this matter. The drafting team notes that entities may change the configuration or operation of their network to facilitate compliance but not to eliminate a compliance obligation. No change made. If transformers are to be included, an exception should be provided to allow the start-up transformer to be used to provide auxiliary power in case of failure of the auxiliary transformer. BES reliability is better served by allowing this exception (which will occur very infrequently) than to keep the generating unit off line for fear of being out of compliance with a standard. **Response:** The drafting team contends that if this is an anticipated operating condition, the protective relays on the alternate source of station service would need to be compliant with the standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Bonneville Power Administration	No	While the Guidelines and Technical Basis provides useful information, BPA is concerned that this document will not be approved by FERC as part of the standard and thus the standard must be capable of standing on its own. For this reason, BPA requests that clarification provided in the Guidelines and Technical Basis document be included into the standard specifically in regards to 'generator interconnection facilities'.
Response: The drafting team thanks you for your comments and will re-append the Guidelines and Technical Basis document to the standard prior to filing with FERC. The documents were separated for management purposes and to facilitate editing between team members. No change made.		

Organization	Yes or No	Question 3 Comment
AESI Inc.	No	Please see comments on Question 2.
Response: The drafting team thanks you for your comments; please see the above responses in question 2.		
Western Farmers Electric Cooperative	No	See comments to question 5
Response: The drafting team thanks you for your comments; please see the responses below in question 5.		
Xcel Energy	No	In the last paragraph on page 19 of the clean version of the PRC-025-1 Guidelines and Technical Basis, the following sentence appears: "Phase time overcurrent relays applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard." This typically would be the case for UAT's connected to the generator bus. However, for system connected auxiliary transformers as shown in Fig 6 on page 20, it is very unlikely that the time overcurrent relays protecting the system connected transformers will act to trip the generator directly or via lockout as this is a different zone of protection and to do so might result in an unnecessary challenge of the unit's overspeed protection. Instead, these overcurrent relays will trip the source breakers feeding the system connected auxiliary transformer but will not act to directly trip the generator. The generator will ultimately trip because of the resultant loss of power to the auxiliary system when the source breakers feeding the auxiliary transformer are tripped. The loss of auxiliary power will likely result in some form of a turbine/prime move trip and the generator breaker will be tripped open once power output drops to zero. In this manner, unit overspeed protection is not unnecessarily challenged. It seems that the quoted sentence on page 19 only serves to confuse the matter. If the goal of this setting requirement is to not to have the plant trip due to a loss of auxiliary power based on overly conservative setting of overcurrent relays, it is immaterial

Organization	Yes or No	Question 3 Comment
		whether the overcurrent relays act to trip the generator directly or via lockout or auxiliary tripping relay or if the plant ultimately trips because a loss of auxiliary power caused by overcurrent relays opening source breakers to the system connected auxiliary transformer. We recommend the quoted sentence be stricken from the guideline and technical basis document.
Response: The drafting team thanks you for your comments and contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
ReliabilityFirst	No	1) There appears to be an error in the Guidelines and Technical Basis document on page 23 for option 15b. It indicates that the Reactive Power output that equates 120% of the maximum gross Mvar output whereas Table 1 states 100%. **Response:** Yes, this was an error in the Guidelines and Technical Basis document for Option 15b. The value should be 100% of the output determined by simulation like the other options. Change made. 2) A statement should be inserted that the iterative calculation stopped because the change was < 1%. This applies to options 1b & 7b on page 31 and option 2b on page 38. Also, if an entity knows the resistive and reactive impedances of the transformer, the entity could directly calculate the low-side GSU voltage from the high-side voltage, the per unit current through the GSU and the full impedance of the transformer. **Response:** This convergence of the equation is addressed for Options 1b and 7b in the calculations above Equation 14. This text was not provided in the calculation for Option 2b; therefore, it will be added to improve overall clarity. There are two variables in this calculation which depend on each other; therefore iteration is necessary. Change made.

Organization	Yes or No	Question 3 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Ameren	No	(1) We request the SDT to add a multiple winding transformer example. We recommend that the SDT include an example with equally rated CTGs connected to equally rated dual secondary transformer windings stepping up to a single high voltage winding, because it is commonly used. **Response:** For the configuration above, the GSU relays will be set on an aggregated generator basis. The generator relay setting will be set on an individual generator basis. The drafting team contends that the calculations provide adequate direction for this configuration. No change made. (2) The MW capability reported to the Transmission Planner changes by a very small amount from time to time. As written we believe that this could trigger a significant amount of documentation. We request the SDT to show in your example (s) how an increased margin would address such a small change (e.g. a 2% increase from the originally documented value) before triggering such a review. **Response:** The drafting team contends that if an entity is concerned about minor changes in the reported capability, the entity can reflect these minor changes as increased margin in their relay setting. No change made. (3) On page 2 of the Guidelines and Technical Basis document, we ask the SDT to delete 'Generator Owner' from the last sentence of Figure 2 caption. **Response:** This was recognized as an error after the posting. The "Generator Owner" has been removed from the Figure 2 text. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Figures 1, 2, and 3 do not provide a sufficient bright line between the application of PRC-025-1 and PRC-023-3 for setting criterion. Luminant recommends that additional

Organization	Yes or No	Question 3 Comment
		information be added that identifies that a load responsive relays located on the transmission line breaker at Bus A and are primarily installed for transmission line protection use PRC-023-3 criterion Requirements R1 through R6 (regardless of the number of generators or transmission lines connected to Bus A). Load responsive relays located on the high side of the GSU and are primarily used for failed transmission line protection should use PRC-023-3 (Attachment C) or PRC-025 (Table 1).
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Tri-State G&T	No	The generator overload protection exception added to Draft 3 for extremely inverse characteristics is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU?
Response: The drafting team thanks you for your comments and notes that the phrase full load current refers to rated armature current of the generator. No change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
Entergy Services, Inc.	No	The Guidelines are still not clear about what to do with start-up transformers when

Organization	Yes or No	Question 3 Comment
(Transmission)		used in lieu of the UATs (Unit Auxiliary Transformer).
Response: The drafting team thanks you for your comments and contends that if this is an anticipated operating condition, the protective relays on the alternate source of station service would need to be compliant with the standard. No change made.		
Tennessee Valley Authority	No	
Operational Compliance	Yes	See comments for Question #1. In addition, Figures 1,2 and 3 could be clarified by 1) labelling the Generator Interconnection Facility with a pointer and parentheses, 2) include table with columns for Relay Owners, Function of Owner and Applicable Standard. This way, a quick glance at the figure can clarify which standard is applicable (rather than having to decipher the caption).
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company;	Yes	

Organization	Yes or No	Question 3 Comment
Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
FirstEnergy	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Ingleside Cogeneration LP	Yes	
Southwest Power Pool	Yes	
Kansas City Power and Light	Yes	

4. The drafting team developed an Implementation Plan for the added requirements of the proposed PRC-023-3 that aligns with that proposed in PRC-025-1. Do you agree with the proposed Implementation Plan for PRC-023-3 Requirements R7 and R8 and the proposed PRC-025-1: a. 48-months to apply load-responsive protective relay settings , where relay replacement is not required, and b. 72-months to apply load-responsive protective relay settings, where relay replacement is required? If not, provide an alternative implementation plan with specific rationale for such an alternative period.

Summary Consideration: Only a minority of commenters provided comments regarding the Implementation Plan. In past postings, a number of commenters suggested increasing the Implementation Plan due to varying factors. The drafting team was reluctant to increase the period beyond the 48 months for applying settings on relays that do not requirement replacement and 72 months for those relays which require replacement or removal. Four comments supported by 11 entities propose lengthening the period in these comments. However, based on other factors identified in question 2, the drafting team has lengthened the Implementation Plan from 48 to 60 months for applying settings on relays that do not requirement replacement and from 72 to 84 months for those relays which require replacement or removal.

One comment noted a lack of clarity on the implementation of PRC-023-3. The drafting resolved that by removing the proposed Requirements R7 and R8 and adding the Distribution Provider and Transmission Owner to PRC-023-3. One comment suggested adding the word “removed” in the “replacement” timeframe for clarity. The drafting team agreed and made the change. Another comment disagreed with the 100 percent compliance approach. The drafting team did not have any flexibility to investigate other compliance approaches. One comment suggested a phased approach to the Implementation Plan; however, the drafting team agreed the current two-phased approach is the most practical. Last, one comment suggested adding formatting to the effective date language to draw attention to “do require replacement” and “do not requirement replacement.” The drafting team did not agree the suggestion provided a substantive improvement to clarity.

Organization	Yes or No	Question 4 Comment
Duke Energy	No	Duke Energy schedules some of its generating units on a 24 month cycle for minor outages and a 96 month cycle for major outages. This would make the current

Organization	Yes or No	Question 4 Comment
		Implementation Plan very expensive and difficult to comply with if relay replacements are required. [Duke Energy suggests a 48 month and 96 month Implementation Plan. This would allow for the industry to use existing outage schedules, keeping overall costs at a minimum.]
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made.		
JEA	No	Considering that applying new settings and testing will require a major outage, we believe that 48 months is not a sufficient time frame for full implementation when existing equipment can be used and relay replacement is not required. We recommend 72 months be allowed even in the case where existing equipment can be used. It may take a year or more to perform the calculations and evaluated equipment and then another 5 years for a major planned outage to occur.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made.		
DTE Electric	No	Comments: Suggest that allowing 72 months to become 100% compliant for both 4a and 4b would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60		

Organization	Yes or No	Question 4 Comment
months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. Also, it is beyond the drafting team's control to ensure that a standard is approved and implemented in such a way to facilitate alignment with the implementation of other standards. No change made.		
American Electric Power	No	Regarding PRC-025-1: While AEP appreciates the factors considered by the drafting team when developing the proposed implementation plan for PRC-025-1, the plan as proposed will not afford adequate time for large Generator Owners to comply with the standards. AEP has 119 generating units and 2 wind farms that are applicable to PRC-025-1. The resources needed to evaluate the generating units for compliance with PRC-025-1 and PRC-023-3 will also be engaged in implementing the new NERC standards PRC-019-1 and PRC-024-1. For these reasons, AEP believes a phased implementation plan for PRC-025-1 is more appropriate. Such a plan would require entities to show that a minimum percentage of their applicable relays are compliant within a specified time frame. For example: * Entities shall demonstrate that 30% of their applicable load-responsive protective relays are fully compliant with R1 within 48 months of the effective date of this standard. * Entities shall demonstrate that 60% of their applicable load-responsive protective relays are fully compliant with R1 within 60 months of the effective date of this standard. * Entities shall demonstrate that 100% of their applicable load-responsive protective relays are fully compliant with R1 within 72 months of the effective date of this standard. Regarding PRC-023-3: The proposed revision could significantly impact Transmission

Organization	Yes or No	Question 4 Comment
		Owners. Additional research is being conducted within AEP Transmission to determine the extent of that impact. It is possible that the proposed implementation plan would not provide adequate time to achieve compliance with the standard if it is determined to impact a high volume of facilities. Additional research will be needed before a recommendation be made on the extent the additional time required. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into PRC-025-1, rather than adding Requirement R7 and R8 to PRC-023-2. All implementation will be addressed within the Implementation Plan for PRC-025-1. The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. The suggested phased-in approach would be potentially unfair to small entities requiring them to become 100% compliant earlier. No change made. It is still unclear when TOs, GOs and DPs will be required to complete loadability evaluations for any circuits below 200kV included by the Planning Coordinator per Attachment B. It is understood that we will have 39 months to apply the initial list. There is confusion however on whether or not the 39 months applies to new inclusions to the list. AEP requests that this time frame be clarified and included in the standard, as it is information needed to maintain compliance on an ongoing basis. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities

Organization	Yes or No	Question 4 Comment
		will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. All implementation will be addressed within the Implementation Plan for PRC-025-1, and no changes are being made to the existing approved PRC-023-2 Implementation Plan.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Luminant recommends that the phrase “where relay replacement is not required” and “where relay replacement is required” add the word removal; i.e., “replacement or removal”.
Response: The drafting team thanks you for your comments and the drafting team has revised items #7 and #8 in the General Considerations of the PRC-025-1 Implementation Plan as you suggest. Change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP does not agree with the 100% compliance approach that the drafting team has taken in regard to PRC-025-1. Although FERC Order 733 is cited multiple times as the reliability need, there are real dollars that the industry will need to expend to analyze and replace load responsive relays for generators of any size. We do not read Order 733 the same way - and FERC has accepted exceptions for low-impact facilities in the past.
Response: The drafting team contends that the requirements proposed within PRC-025-1 satisfy the associated FERC directive and are appropriate and necessary. Appendix 4B, Section 2 of the NERC Rules of Procedures identify and discuss the basic principles underpinning why and how NERC and the Regional Entities will determine Penalties, sanctions, and Remedial action Directives for violations of the Requirements of the Reliability Standards. By being classified as BES, the facilities involved have been determined to have impact on the reliability of the BES. No change made.		
Luminant Energy	No	See Luminant Generation Company LLC comments.

Organization	Yes or No	Question 4 Comment
Company LLC		
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
ACES Standards Collaborators	Yes	We agree with the 48-month and 72-month implementation plan for PRC-025 and R7 and R8 in PRC-023. However, we believe the implementation plan for PRC-023 as a whole is confusing. Since PRC-023-2 has a staggered implementation plan that is still has not fully been implemented, we recommend laying out a graphical timeline or a Gantt chart that compares PRC-023-2 implementation to that of PRC-023-3.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are known to improve clarity. Change made. The drafting team is unable to provide a graphical timeline comparison between the standards illustrating their implementation because each is subject to NERC Board of Trustees adoption and subsequent regulatory approvals. No change made.		
Operational Compliance	Yes	Editorial note: To aid with distinguishing between options: underline the words “is necessary” and “is not necessary” for “Implementation Date” columns.
Response: The drafting team thanks you for your comments and contends that it is not necessary to add the emphasis suggested.		

Organization	Yes or No	Question 4 Comment
No change made.		
Pepco Holdings Inc. & Afffiliates	Yes	
FirstEnergy	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
PPL NERC Registered Affiliates	Yes	
Western Area Power Administration	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
AESI Inc.	Yes	
Chelan County PUD	Yes	

Organization	Yes or No	Question 4 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst	Yes	
Ameren	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Southwest Power Pool	Yes	
Kansas City Power and Light	Yes	

5. Do you have any other comments? If so, please provide suggested changes and rationale.

Summary Consideration: The general section of the comments contain varying issues, some being majority issues that have been addressed in previous postings. There are approximately ten chief concerns. (1) About eight comments supported by 45 stakeholders disagreed that the unit auxiliary transformer (UAT) should be addressed in the standard. The drafting revised the criteria for the UAT to address only those relays on the high-side terminals of the UAT. The drafting team acknowledges the varying configurations of station service supply and agrees that addressing loadability of the UAT is best satisfied at the high-side terminals of the UAT to be responsive to the FERC directive to include them. (2) Approximately five comments represented by about 41 entities disagree with the singe Violation Severity Level (VSL) of Severe. The drafting team contends it has followed the VSL Guidelines and notes that the requirement applies to each load-responsive protective relay. Violations would be evaluated on a case by case basis through the auditing and enforcement process. (3) About six comment supported by 36 stakeholders disagreed with the inclusion or impacts the standard would have on Blackstart generation units and dispersed generation. The drafting team considered these issues and determined that the governing factor should be the application of the Bulk Electric System definition which addresses whether a unit or plant is BES based on individual unit size or site aggregate capacity. (4) Four comments representing about 29 entities disagreed or requested clarity about the use of the phrase “generation interconnection Facilities.” The drafting team addressed this by rephrasing this criterion to avoid confusion with the common understanding. See Question 1 summary and comment responses for more detail. (5) Two comments supported by about 28 individuals desired an approach similar to the PRC-024 standard. The drafting team noted that PRC-024 is based on equipment potentially being damaged and the proposed PRC-025-1 standard criteria achieve its loadability goal in conditions that are not damaging to the generator. (6) Approximately three comments represented by 19 stakeholders suggested using the generator nameplate to reduce the complexity of the criteria. The drafting team addressed this in prior postings and in the above summaries. The proposed PRC-025-1 standard takes into consideration that some generation units may not operate near nameplate capacity; therefore, using a nameplate value would be result in an overly conservative setting. (7) Two comments representing 19 individuals did not agree with the intent of the standard. The drafting team is certain that is has fulfilled its responsibility in meeting the objectives of the project to address load-responsive protective relay loadability for generation Facilities. (8) Three comments supported by about 18 entities expressed concern about the proposed Requirements R7 and R8 in PRC-023-3. The drafting team removed these requirements and added the Distribution Provider and Transmission Owner in PRC-025-1. See the above summaries and comments for more detail. (9) About four comments supported by 11 stakeholders raise concerns about overloading and the application of ANSI standards in relation to the PRC-025-1 standard. The drafting team provided responses to help clarify the differences. Please see the individual responses for greater clarity on overload issues. (10) The last of the chief concerns were noted in three comments represented by 12 individuals who expressed disagreement with a Violation Risk Factor (VRF) of High. The drafting team notes that the assignment of the VRF follows VRF guidelines.

The following summary addresses concerns of two or fewer comments and less than ten individuals. Stakeholders continued to have concerns about the phrase “while maintaining reliable fault protection.” This phrase has been used in previous versions of PRC-023 and the drafting team agrees that it is clear on the expectation. Comments supported by about six entities requested terms in PRC-023-3 to be capitalized to represent NERC glossary definition terms; however, the drafting team did not address these as they are outside the scope of the approved objectives of the project. Another set of comments supported by about eight individuals requested the removal of the “Regional Reliability Organization (RRO) from the standard. The drafting removed this language and to address the potential gap in doing so, increased the Implementation Plan periods by one year. See the summary in Question 2 and individual responses for more detail. Last, single comments asked for clarification of BES generators, minor edits and corrections, Implementation Plan edits, and consideration of the Reliability Standard Audit Worksheet (RSAW) and the Cost Effective Analysis Process (CEAP). See the responses for the RSAW and CEAP for additional detail.

Organization	Yes or No	Question 5 Comment
Pepco Holdings Inc. & Afffiliates	No	
Western Area Power Administration	No	
Duke Energy	No	
PacifiCorp	No	
Idaho Power Company	No	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	No	
Northeast Utilities	No	
South Carolina Electric and Gas	No	
Luminant Generation	No	
Luminant Energy Company LLC	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	2) We suggest removing Section 3.2.3 and footnote 1. UAT protection is part of the station service system and should not be in this standard. Remove the UAT from Table 1. The UAT relays are not in the category of "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." The highside overcurrent pickup should not be required to be at 150%. Settings at > & = 115% should be allowed. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. The specified relays are affected by the conditions being addressed by the standard, and thus need to be addressed. The drafting team has proposed a 150% multiplier for these relays rather than requiring an analysis of the connected loads for depressed voltage; the margin includes consideration for the increased current called for by these

Organization	Yes or No	Question 5 Comment
		loads as well as normal relay setting tolerances. No change made. 3) We believe that the Purpose statement should end "... do not pose a risk of damaging the generator." **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. 4) The protection of the generator should be the paramount concern. All ANSI standards for generator and main power transformer protection should be considered to be the ruling guide for protecting the equipment. The minimum allowable settings provided in the table in the draft standard do not factor using time delays in order to provide adequate protection for generators. **Response:** The ANSI/IEEE standards are voluntary and are generally written from an equipment-specific perspective. The drafting team notes that they do, in many cases, mention system performance, and the concerns noted in the ANSI/IEEE standards for system performance do not differ greatly from the criteria proposed in PRC-025-1. The drafting team further notes that the IEEE working groups that develop these standards are considering revisions to the affected standards to align with the Power Plant and Transmission System Protection Coordination document authored by the NERC SPCS. Finally, the drafting team notes that the last two bullets in the Exceptions in PRC-025-1 Attachment 1 address overload protection. No change made. 5) The overload relay that protects the generator from overload may also be the relay that protects the GSU from overload. In the exception list of the draft standard, exception bullet #5 should take precedence over exception bullet #6. **Response:** In the example noted bullet #5 is applicable and bullet #6 is not. Therefore, the relay is exempted under bullet #5. No change made.

Organization	Yes or No	Question 5 Comment
		6) The protection requirements (exception bullet #5) from the ANSI standards need additional recognition, development, and emphasis in the Exceptions section. As written, it appears to be an afterthought. The ANSI standard for synchronous generator protection should be recognized, respected, and not violated. The Table 1 setting specifications which contradict the ANSI standards should be submissive to the ANSI standards and itemized in the exception criteria. Consider removing “extremely” from the "extremely inverse time" description as various vendors call the varying inverse time curve by different names. **Response:** The ANSI/IEEE standards are written from an equipment-specific perspective, and largely disregard system performance concerns. The drafting team notes that they do, in many cases, briefly mention system performance, and the concerns noted in the ANSI/IEEE standards for system performance do not differ greatly from the criteria proposed in PRC-025-1. The drafting team intends that “extremely inverse characteristic” be applied consistently with IEEE C37.112, “IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays.” No change made. 7) The generator overload protection exception added to Draft 3 for extremely inverse characteristics (fifth exception bullet) is an improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, the value determined from the generator nameplate MVA at rated voltage, or is it the base or top (no fans, no oil circulation) MVA rating of the GSU? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 8) The wording in the sixth exception bullet of the Exceptions section is too vague. How much of an overload is considered an overload? Many vendor relay curves do not provide characteristics showing the value of current that will time out in 15 minutes. It may be difficult to prove a setting to provide 15 minute delay. Existing relays in service

Organization	Yes or No	Question 5 Comment
		do not have the ability to be set by this criterion. **Response:** The drafting team does not intend to define what an overload is, but instead to exempt schemes that are explicitly designed for overload protection, for which characteristics would be defined for the time period in the bullet. Load-responsive relays that respond otherwise must meet the criteria in Table 1. No change made. 9) The Exceptions section seems to state that the exceptions are allowed only during start up and when off line, which is unacceptable. The exceptions should be allowed at all times. **Response:** The drafting team has revised the exceptions portions of Attachment 1 to address your concerns by inserting a specific numbered exception to adder relay elements that are in service only during startup. Change made. 10) To meet the requirements of table 1 for non-51 relays (distance relays set at approximately 180% of generator MVA) and meet our protection philosophy objectives, we would have to install many new relays for overload protection. **Response:** The drafting team understands that in some cases it may be necessary to replace existing relay equipment. No change made. 11) Determination of the pickup of the distance relays is too complicated. The calculated impedance should be based on generator nameplate MVA and pf only. The requirements make what should be a simple calculation based on generator electrical characteristics into one that will require the relay engineer to find test MW data is not readily unavailable. **Response:** The drafting team intentionally did not reference the calculation to nameplate MVA for the Real Power portion of the calculation because this would result in an overly conservative setting for units that cannot achieve the nameplate capability. The test megawatt data must be reported and should be readily available.

Organization	Yes or No	Question 5 Comment
		No change made. 12) PRC-025 should be revised to "grandfather" existing protection settings that have been proven in practice for many decades not to prematurely remove equipment from service. **Response:** The drafting team has developed the standard in accordance with the regulatory directive concerning generator relay loadability, which is an outcome of the 2003 blackout report. As noted in the NERC document 'Power Plant and Transmission System Coordination' – July 2010, at least 28 generators were tripped on August 14, 2003 by load-responsive phase protection; eight of those by phase distance and 20 more by 51V protection. For many of these generators, the legacy protective equipment had been previously believed to not prematurely remove equipment. No change made. 13) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, whose tripping would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings for retoration purposes. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 14) Voltage-restrained overcurrent relays are notorious for not having a predictable operation time under fault conditions. If they are included in the types of equipment that mis-operated in the August 2003 blackout, they should be required to be replaced with another relay type rather than requiring that the settings be relaxed to the degree

Organization	Yes or No	Question 5 Comment
		specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 15) A High VRF and a Severe VSL seems overly harsh given the compliance feasibility uncertainties. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made. 16) Which UATs are proposed to be included, if any, is confusing. Suggest adding diagrams to the reference document. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 17) During the webinar there were three slides related to the different trans to Gen interconnections and who is responsible for what; suggest adding and or clarifying these in the reference documents. **Response:** The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are

Organization	Yes or No	Question 5 Comment
		covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Northeast Power Coordinating Council	Yes	In PRC-023-3, add “Each” to the beginning of R8.
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
FirstEnergy	Yes	FE believes that that the term "generator interconnection Facility" should be a NERC defined term in the Glossary since it is used in other standards, ie, PRC-005, or at the very least, be defined within the standard(s). This term is only defined in the Guidelines and Technical Basis. In the Guidelines and Technical Basis, Figure 2 has a typo on the 3rd sentence and should read as follows: If the Distribution Provider or Transmission Owner owns these relay, they are responsible for them under PRC-023.
Response: The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.		
SERC Protection and Controls Subcommittee	Yes	There were three one-line reference drawings described on the webinar. Suggest adding text to these reference drawings or add descriptive wording in reference documents to better explain responsibilities of relay owners for these various

Organization	Yes or No	Question 5 Comment
		configurations. On the webinar there were repetitive questions about these configurations so this would indicate confusion. Also, would suggest adding another drawing to illustrate when you have a generating station where the GO owns GSU relays and the TO owns relays between the GSU and switchyard to clarify that the TO is only responsible for R7 in PRC023-3 and not R8 since the GSU relays are a GO asset.
Response: The drafting team thanks you for your comments and notes that these figures are already included in the Guidelines and Technical Basis, along with discussion. No change made.		
PPL NERC Registered Affiliates	Yes	: The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” Unit Auxiliary Transformers (UAT’s) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3.The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ‘03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities’ UATs in Section 3.2.3 do not belong in this standard as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT’s lack of impact on generator loadability should be considered by the SDT.

Organization	Yes or No	Question 5 Comment
		A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2.) The generator overload protection exception added to Draft 3 for "extremely inverse characteristics" (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that "full-load current" is understood to be the generator nameplate MVA at rated voltage **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 3.) The overload protection exception added to Draft 3 for "extremely inverse characteristics" should be applied for UAT's as well if eliminating UAT's in its entirety (per comment #1 above) does not prove feasible. **Response:** The exclusion #7 addresses transformers and is not limited to only GSUs. No change made. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the

Organization	Yes or No	Question 5 Comment
		time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan

Organization	Yes or No	Question 5 Comment
		(i.e., SRP). No change made. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made. 8.) The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing. **Response:** The drafting team continues to support the proposed draft standard as currently structured. The current draft requirements allow Compliance Enforcement Authorities to take into account an entity's process in connection with the required activities. How compliance will approach a standard is appropriate for the

Organization	Yes or No	Question 5 Comment
		development of the RSAW. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
North American Generator Forum Standards Review Team	Yes	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 3. The exception of comment #2 above, which is presently limited to generator overloads, could be applied for UATs as well if eliminating this equipment in its entirety

Organization	Yes or No	Question 5 Comment
		(per comment #1 above) does not prove feasible. **Response:** The exclusion #7 addresses transformers and is not limited to only GSUs. No change made. 4. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 5. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the

Organization	Yes or No	Question 5 Comment
		applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 6. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 7. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Dominion	Yes	PRC-025 -1 Requirement 1: remove the following words: "...while maintaining reliable fault protection." It is not possible for entities to measure or prove this statement. The wording, "while maintaining reliable fault protection", is also included in the Introduction section of PRC-025-1 Guidelines and Technical Basis. The inclusion "describes that the Generator Owner is to comply with this standard while achieving its desired protection goals." Dominion believes that the Generator Owner

Organization	Yes or No	Question 5 Comment
		understands the compliance obligation based upon the requirements of the standards and that the inclusion of the referenced language should be excluded based on the inability of the entity to measure or provide evidence of maintaining reliable fault protection. **Response:** The drafting team contends that the description of the term "while maintaining reliable fault protection" found in the Requirement R1 rationale box adequately conveys the suggested intent. No change made. PRC-025-1: Redline - Page 6 of 18 Table of Compliance Elements; An indication of Lower VSL. Moderate VSL or High VSL needs to be determined with regard to R1. Dominion disagrees with the "all or nothing" approach to VSLs. **Response:** The specified VSL applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. PRC-023-3 Implementation plan; Redline Pages 3-6, R1-R6 the Requirement wording (in the Applicability column) does not exactly match the Requirement wording in the standard. Dominion suggests correcting the wording to match the Standard as written. **Response:** The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. PRC-025-1 @ figure 3 - Dominion does not necessarily agree that these lines are part of networked transmission and therefore would not be considered as generator interconnection Facilities. Dominion believes the designation of the lines should be based on registration of the asset owner and will be providing supporting comments in response to the FERC NOPR in docket # RM12-16-000. **Response:** The drafting team asserts that the lines in Figure 3 can be expected to carry network flow, are not used exclusively to export energy directly from a BES generating unit or generating plant to the network, and therefore are not generator

Organization	Yes or No	Question 5 Comment
		interconnection Facilities. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Santee Cooper	Yes	Unit Auxiliary Transformers (UATs) should be removed from this standard (Facilities Section 3.2.3). The purpose of this standard is “To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage.” The intent as stated in the Application Guidelines is to pertain to relays that “are affected by increased generator output in response to system disturbances.” UATs do not fit this criteria. Addressing generating plant unit auxiliary transformers does not have to translate into creating a standard requirement for that equipment. An investigation and evaluation of the protection system for unit auxiliary transformers should be considered by the standard drafting team and deemed to be not related to generator loadability and fulfill the FERC order to address the subject.
Response: The drafting team thanks you for your comments and contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
JEA	Yes	We would like to see modifications to violation severity levels. While we recognize the SDT is following NERC binary guidelines “pass/fail”, this needs to be improved. The idea that either they “applied” or “did not apply” settings must result in a “severe” violation level does not match the reality that missing 10 out of 20 poses a greater risk to the BES than 1 out of 100.
Response: The drafting team thanks you for your comments and notes the specified VSL applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. No change made.		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	Yes	Comments: (1) The use of the term generation interconnection facility without an official definition of the term is concerning to BPA. BPA believes that this term may have different meanings between entities. For example, the entire Bulk Electric System (BES) together with all distribution systems could be considered to be a generation interconnection facility because the purpose of the BES and distribution systems is to interconnect generation to the end user (load). Only under the Guidelines and Technical Basis is a description of what a generator interconnection facility found.BPA is concerned with this approach as it does not give an official definition, and this document is not part of the standard. Additionally, BPA believes the description of generator interconnection facility given in the Guidelines and Technical Basis creates problems. The description provided is that the generation interconnection facility consists of elements between the generator step up transformer (GSU) and the interface with the portion of the BES where the Transmission Owner (TO) takes over the ownership. In many cases the TO owns the line that connects to the generator step up (GSU) transformer and there are no elements between the GSU and the TO. According to this description there is no generation interconnection facility. Due to the ownership arrangements of transmission, generation, and their interconnection facilities throughout the country are highly variable, BPA believes it is not suitable to develop a definition of generation interconnection facilities based on ownership. Such a definition may reflect the ownership arrangements within a particular region while it does not take into account various other arrangements that may exist. BPA recommends for the drafting team to provide a definition of generation interconnection facility that takes into account the various ownership situations that may exist. **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.

Organization	Yes or No	Question 5 Comment
		(2) BPA believes the use of the word associated in the purpose statement of PRC-025-1 as well as in Section 3.2 Facilities is too vague and recommends this term be changed to "whose function is the protection of generation Facilities..." in the purpose statement and Section 3.2 be rewritten to read "3.2 Facilities: The following Bulk Electric System Elements, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:" **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Tennessee Valley Authority	Yes	Is the intent of this standard to identify the lines in their normal configuration and not for contingency events? For example, referring to Figure 3 from the Webinar, if a line is lost, causing the system configuration to change to what is shown in Figure 1, does this mean that the configuration then is considered to fall under R7?
Response: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. The intent of the standard is based on lines in the normal configuration as being presented in the Figures. No change made.		
ACES Standards Collaborators	Yes	(1) We are not convinced that applicability of PRC-023 R7 and R8 to a Distribution Provider is necessary. It would be unusual for a generator that meets BES definition criteria and compliance registry criteria to be connected to a Distribution Provider.

Organization	Yes or No	Question 5 Comment
		Both criteria require a single generator to be 20 MVA or a plant site to be 75 MVA. From a practical perspective, this could actually be a detriment to reliability by distracting the Distribution Provider from reliability activities because they have to focus on documenting that they do not have any applicable generators connected. How does including the Distribution Provider as an applicable entity benefit reliability? **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. Even though it may be unlikely that such a Facility would be connected to a Distribution Provider, the drafting team contends that providing for such a condition in PRC-025-1 would assure that no gaps exist for this situation. (2) The High VRFs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are inconsistent with established NERC criteria. In order to meet the High criteria, a single violation of the requirement “could directly cause or contribute to bulk electric instability, separation or a cascading sequence of failures.” A single failure to have a relay set to avoid loadability concerns on a single generator could not lead to instability, separation or cascading without violating other standards. For example, TOP-004-2 R2 already require N-1 operation so a single generator tripping due to relay loadability issues would require at least two standards requirements violations. This cannot be viewed as “directly” causing. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, “… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system

Organization	Yes or No	Question 5 Comment
		instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. No change made. (3) We believe the VSLs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are written inconsistent FERC guideline 3 which states that the VSL cannot change the requirement. The plain language of the requirements is written in a plural format as though the requirement considers all relays are considered simultaneously. The VSLs are written such that each relay that is not set appropriately is a separate violation. The VSLs, in essence, change the requirements. For example, the Requirement for PRC-023 R7, states "shall set their load responsive relays," while the VSL essentially modifies the requirement to state "shall set each load responsive relay." We recommend modifying the VSL to be in better alignment with the requirement. **Response:** PRC-025-1 has only one Requirement R1 (not R2) which applies separately and individually to each protective relay (singular) addressed; therefore it is not possible to grade the VSL. No change made. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. In removing Requirements R7 and R8 from PRC-023-3, the plural use of "relays" is no longer relevant. Change made. (4) The wording in the second sentence of the second paragraph in PRC-023 Attachment C needs to be fixed. There seems to be an extra "Facilities."

Organization	Yes or No	Question 5 Comment
		Response: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. The comment is no longer relevant; however, the drafting team updated the similar occurrence in the PRC-025-1 Attachment 1 to "Elements" which more correctly identifies those Facilities which are subject to the standard. Change made. (5) RRO is used throughout both standards. It should be Regional Entity, as stated in NERC's legal memorandum on the "Use of 'Regional Reliability Organization'..." The memo states that in general, drafting teams can replace "RRO" with "RE," provided the functions being performed by the RE are related to their delegated duties. Reliability Standards that refer to REs are legally binding on the REs by operation of Rule 100 of NERC's Rules of Procedure and by the delegation agreements that NERC has entered into with each RE. **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made. (6) Please strike "other entity as specified by the Regional Reliability Organization (RRO)" that is used throughout Attachment C in PRC-023 and Attachment 1 in PRC-025. It creates compliance uncertainty and provides the Regional Entity far too much discretion. If the purpose is an attempt to document from other standards where the nameplate rating is communicating, we suggest that the drafting team perform a search of the other standards and explicitly document the entities. Otherwise, the Regional Entity, as the standard is worded, could simply decide to move the dates.

Organization	Yes or No	Question 5 Comment
		FERC has ordered NERC to remove regional discretion from standards development, such as the revision of the BES definition. **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made. (7) We appreciate the relay elements that are identified for exclusion in PRC-023 Attachment C. However, we believe that the exclusion should be identified explicitly in Attachment A as well. Attachment A is referenced in applicability section. We are concerned since attachment C is not referenced in the applicability section that exclusion of the relay elements could be lost. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. (8) We disagree with the applicability of 3.2.5. We not understand how applicability to a distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can understand inclusion of the main GSU for a large site but not the individual collector elements. **Response:** The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar

Organization	Yes or No	Question 5 Comment
		load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
AESI Inc.	Yes	This draft of the standard uses 0.85 pu transmission system voltage as a benchmark for determining the settings. The latest version of PRC-024-1 defines post-disturbance voltage profile where the system voltage is below 0.85 pu up to 3 seconds. Is there a need to take that into consideration for this standard.
Response: The drafting team has coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made.		
Chelan County PUD	Yes	1. Please, reconsider the applicaiton to small units that are "black start" or auxiliary units in a BES plant. Application of these requirements to a small (750kW) hydro unit that is black start is problamatic particularly due to the age of many of these units. It is difficult to see where loss of a unit of small size would impact the BES during this type of event. Please, consider a minimum size threshold for units where these requirements would be applicable. Perhaps 20MW as is used in the BES definition would be appropirate. Consider also an exclusion for a small unit, say less than 5MW, that is part of an aggregate plant of larger units that exceeds the 75MW plant threshold. An example is our 750kW hydro unit that is in the plant with ten 25MW units. It seems excessive to apply this to the 750kW unit. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system

Organization	Yes or No	Question 5 Comment
		restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. The applicability is consistent with the definition of the BES. No change made. 2. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 3. Clarify UAT and station service transformers. Footnote 1 says "Loss of these transformers will result in removing the generator from service." Does that mean it only applies to SS transformers that loss of will remove a unit from service? What about provisions for backup, multiple transformers and busses? Consider an hydro plant with 4 sation service busses and 12 generating units. Would this standard apply to all? This is very different from thermal stations where a unit would have a dedicated transformer that without its power the unit will trip. Consider liminting this only to transformers where loss would cause a direct trip of a BES unit, or eleminiate

Organization	Yes or No	Question 5 Comment
		UAT ans SS transformers completely per comment 2. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 4. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU, or FERC hydro nameplate criteria at best gate? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 5. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection.

Organization	Yes or No	Question 5 Comment
		No change made. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. Consider a VSL based on the size of the generating unit or amount of generation that would be lost if the standard were not properly applied. A 20MVA unit would have a much lower impact on the reliability of the BES than a 500MW unit. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also contends that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL; therefore the VSL is binary regardless of the size of the generating unit. No change made. The drafting team contends that the requirements proposed within PRC-025-1 satisfy the associated FERC directive and are appropriate and necessary. Appendix 4B, Section 2 of the NERC Rules of Procedures identify and discuss the basic principles underpinning why and how NERC and the Regional Entities will determine Penalties, sanctions, and Remedial action Directives for violations of the Requirements of the Reliability Standards. By being classified as BES, the facilities involved have been determined to have impact on the reliability of the BES. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 5 Comment
Western Farmers Electric Cooperative	Yes	Many generation Facilities, that are part of the Bulk Electric System, became commercial in the 1950's, 1960's, 1970's, 1980's and 1990's. These Facilities should be Grandfathered in. Many of these units, although reliable, it may not be cost effective to obtain compliance with PRC-025-1. Many of these Facilities would be forced to either: (1) implement very expensive upgrades to existing equipment, (2) replace existing equipment, (3) retire the Facility. It's my opinion this is not consistent with the economic rational NERC is attempting to achieve. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. Secondly, the Violation Risk Factor of High, seems extreme because several other standards address generator reliability (Under-frequency, Misoperations, Protection System Maintenance and Testing, Generator Verification). These standards, have resulted in many generation Facilities having undergone relay coordination studies to prevent an occurrence similar to the 2003 "blackout." **Response:** These other standards do not address the conditions being addressed by this standard. No change made.

Organization	Yes or No	Question 5 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Xcel Energy	Yes	1) Applicability: In the applicability sections, we suggest you replace the phrase "BES generating unit or generating plant" with "BES generating unit or BES generating plant" to be more clear. **Response:** The drafting team contends that the adjective, “BES” clearly applies to both the generating unit and the generating plant. No change made. 2) M1: We recommend you add “simulation results” as acceptable evidence in Measure M1. (reason: Some people may choose to do PRC023 check in the CAPE simulation.) **Response:** This is existing approved content within PRC-023-2 and outside the scope of this project. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Manitoba Hydro	Yes	(1) Section 3.1.1, PRC-025-01 - the repeated word “Facilities” seems unnecessary. For clarity, remove the last instance of the word “Facilities” in the statement: “Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities.” **Response:** The first occurrence of Facilities should have been “Elements” to refer to the numbered list under the section 3.2, Facilities. Change made. (2) Section 3.2 - it would be useful to add criteria that define which generator units should be included as associated with the BES. Alternatively, should this standard refer to the BES definition for which generator units in this standard will apply to? **Response:** This standard includes all generating units and generating plants that are part of the BES, as established by application of the approved definition of Bulk Electric System (BES). No change made.

Organization	Yes or No	Question 5 Comment
		(3) Section 3.2.5 - It is unclear what elements should be included in this section - Collector lines only? What size (MVA) of generating source that the collector line has to be on to qualify as one of these elements? **Response:** The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made. (4) Implementation Plan, PRC-023-3 - it would be helpful to include the implementation plan within the standard **Response:** The Implementation Plan is posted as a separate document with supporting information for industry consideration. Generally, once the standard is NERC Board of Trustees adopted, the effective date information is re-inserted into the standard; however, an entity should always consult the implementation plan for additional information. No change made. (5) PRC-023-3, Purpose - suggest re-wording to the following "...not interfere with a system operators ability to take remedial action to protect system reliability....". **Response:** The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (6) PRC-023-3, Purpose - capitalize "system operator" because it appears in the Glossary of Terms. **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not

Organization	Yes or No	Question 5 Comment
		editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (7) PRC-023-3, Applicability, Functional Entity - capitalize “protection system” because it appears in the Glossary of Terms. **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (8) PRC-023-3, 4.2.1.3 - ‘BES’ should be written Bulk Electric System (BES) since it is the first appearance of the word. **Response:** The drafting team added exclusion text to the Applicability section 4.2.1.1 which occurs before the above referenced section 4.2.1.3; therefore, the BES acronym has been more fully listed as “Bulk Electric System (BES)” in section 4.2.1.1 rather than 4.2.1.3. Change made. (9) PRC-023-3, 4.2.3.1 - should Transmission lines be written “Transmission lines (and paths)”? **Response:** Making such a change introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made.

Organization	Yes or No	Question 5 Comment
		(10) PRC-023-3, R1, 4 - capitalize the words “power transfer capability” because it appears in the Glossary of Terms. **Response:** This phrase is not a NERC Glossary term and perhaps it is being confused with “Total Transfer Capability” (TTC). No change made. (11) PRC-023 and PRC-025 - capitalize the words “transmission lines” throughout the document(s). **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. The phrase “transmission lines” is not used in the proposed PRC-025-1. (12) PRC-023 and PRC-025, D. Compliance 1.1 - the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? **Response:** The language used in the standard in section D. Compliance 1.1, “Compliance Enforcement Authority” is the exact definition taken directly from the NERC Rules of Procedure, Appendix 2, Definitions Used in the Rules of Procedure effective March 5, 2013. No change made. (13) PRC-023-3 - Attachment B, Circuits to Evaluate - replace the acronym “BES” with the words “Bulk Electric System”. **Response:** Change made. (14) PRC-023-3 - Attachment B, Criteria, B2 - write out the words for “IROL” then use

Organization	Yes or No	Question 5 Comment
		the acronym thereafter. **Response:** Change made. (15) PRC-023-3 - Attachment C - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”. **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated; therefore the comment is no longer relevant. Change made. The reference to “…or other entity as specified by the Regional Reliability Organization (RRO)” has been removed from the standard. Change made. (16) PRC-025-1 - Attachment 1: Relay Settings - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”. **Response:** The reference to “…or other entity as specified by the Regional Reliability Organization (RRO)” has been removed from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
ReliabilityFirst	Yes	1) In Attachment 1, it is not clear that the fifth bulleted exception regarding protection systems that detect generator overloads needs or should be as specific as to cite the 7 seconds at 218% of full-load current operating point or characteristic curve. Typically for a fault right on the generator terminals, the current decays in a couple of seconds to around full load current even with the AVR in service. Even during field forcing, it is more likely that the field overcurrent relay would operate rather than a generator overload relay. Therefore, the exclusion does not appear to be needed. If the exclusion is needed, it is recommended that the exclusion be stated in a more general way such as the following: Protection systems that detect generator overloads that are designed to coordinate with the generator short-time capability by utilizing a relay characteristic set to operate no faster than the capability curve and supervised to

Organization	Yes or No	Question 5 Comment
		prevent operation below 115% of full-load current. **Response:** Generator thermal overload protection may be provided by an overcurrent relay as described in clause 4.1.1.2 of IEEE standard C37.102-2006, *IEEE Guide for AC Generator Protection*. This application must be coordinated with the generator thermal capability and would be in conflict with PRC-025-1 unless this exclusion is provided. The drafting team notes that the specific values in exclusion 6 describe a boundary for setting this protection consistent with the generator short time capability and is not prescriptive. No change made. 2) The word 'Each' appears to be missing in Requirement R8 of PRC-023-3. 'Each' should be inserted at the beginning of the requirement before Transmission Owner and Distribution Provider. **Response:** The comment is no longer relevant because the drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. 3) Since there are cases where redundant UATs that allow a generator to continue to remain in service when one UAT trips, this may be rationale to revise 3.2.3 of the Applicability section to indicate exclusion for these configurations. Alternatively, it could be addressed in the Guidelines and Technical Basis document. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.

Organization	Yes or No	Question 5 Comment
		4) The Regional Reliability Organization (RRO) is referenced within both standards and it was ReliabilityFirst's understanding that the term RRO was to be removed from all the standards. In Order 693, Paragraphs 146-148 and paragraph 157 state "The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate." ReliabilityFirst suggests replacing the RRO with the Planning Coordinator (PC) or other registered function the SDT determines to have the wide area view and be responsible for determining what these settings and or values should be. **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Ameren	Yes	(1) The generator overload protection exception on page 8 for "extremely inverse characteristics" (5th bullet-dot) is a major improvement, but we believe that the term "full-load current" needs clarification. We ask the SDT, is this current at 100% of the gross MW capability reported to the TP, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or the smallest of these? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. (2) We believe that Blackstart Resources should be excluded because there is no technical basis for including them. On the contrary, it is more important to assure Blackstart Resources are adequately protected and available for restoration in the

Organization	Yes or No	Question 5 Comment
		extremely unlikely event that a wide-area blackout occurs. Also, we believe that there is no evidence that the tripping of a Blackstart Resources has contributed to widespread outages. In our experience, these resources are below the 20MVA threshold and even if they were on-line and tripped their impact to the BES are minimal. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made**.** (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference. **Response:** Please see the responses to the SERC PCS comments.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Electric Power	Yes	System fed auxiliary transformers whose loss would not result in an instantaneous generating unit trip, and for which operators would have opportunity to reconfigure the plant auxiliary load before a unit trip occurs, should be excluded from this standard. However, if the SDT intends the standard to be applicable to all system fed auxiliary transformers, we recommend removing the text "...that trips the generator either directly or via an interposing/lockout relay" from the standard. This statement is similar to language that entities have used to exclude system fed auxiliary transformers that initiate a process shutdown trip from the scope of other NERC PRC standards. During a disturbance in which system voltage becomes depressed, the generator will

Organization	Yes or No	Question 5 Comment
		respond by increasing excitation in an effort to compensate for the voltage loss. This will result in the generator terminal voltage being greater than the system voltage. For this reason, AEP recommends that settings for applicable relays installed on the generator side of the GSU be based on a generator bus voltage of 1.0 per unit at the generator terminals, rather than a generator bus voltage calculated from 0.85/0.95 per unit of the GSU high-side nominal voltage.
Response: The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made The drafting team acknowledges that the generator terminal voltage during field-forcing will be higher than the transmission system voltage; the drafting team accounted for this in the voltage criteria. No change made.		
Tacoma Power	Yes	Comments 1-4 below pertain to PRC-025-1. 1. Referring to Attachment 1, are phase fault detectors used in current-based local breaker failure schemes excluded from PRC-025-1? **Response:** Yes. The breaker failure relay will assert only if other components fail and is not addressed in the standard; therefore, the associated fault detector is not included. No change made. 2. Referring to Attachment 1, Footnote 3 still has the terms "no-load tap changers (NLTC)" and "on-load tap changers (OLTC)." **Response:** Change made. 3. Referring to page 22 of 68 of the redlined Guidelines and Technical Basis, the first paragraph after "Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays - Directional Toward Transmission System (21) (Options 14a and 14b)," change "...for these relay..." to "...for these relays..." (There are also other instances of

Organization	Yes or No	Question 5 Comment
		this issue.) **Response:** The editorial suggestion is correct. Change made. 4. Referring to page 20 of 68 of the redlined Guidelines and Technical Basis, would the UATs shown in Figure 6 necessarily be applicable to PRC-025-1? It seems that phase time overcurrent relays applied to UATs like these might not “act to trip the generator directly or via lockout or auxiliary tripping relay.” **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 5. Referring to Attachment C, why are only two of the bulleted exceptions shown in PRC-025-1 Attachment 1 brought over? **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. 6. Referring to page 12 of 13 of the redlined Implementation Plan, change “...were added to address to situations...” to “...were added to address situations...” **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are known to improve clarity. Change made. 7. Referring to page 13 of 13 of the redlined Implementation Plan, last row in the table, are references to R7 supposed to be references to R8? Additionally, change “...equally and efficient...” to “...equally efficient...” **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are

Organization	Yes or No	Question 5 Comment
		known to improve clarity. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Tri-State G&T	Yes	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ‘03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to

Organization	Yes or No	Question 5 Comment
		meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 3. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 4. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. The threshold criteria in PRC-025-1 are necessary to prevent tripping from generator load-responsive protective relays for short-time overloads during the field-forcing

Organization	Yes or No	Question 5 Comment
		conditions of the generator, for which the equipment was designed. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Ingleside Cogeneration LP	Yes	In the previous posting, the project team requested our estimated compliance costs and comments on the RSAW. Both of these projects are components of risk-based compliance - which Ingleside Cogeneration LP fully supports. However, it appears that these are not considerations at all in the latest postings. We are not sure what has changed in the intellectual basis of risk-based compliance, but it seems we have taken a step backwards. The rationale for far too many of the project team's consideration of comments was that FERC Order 733 mandated some action. Since FERC has been generally supportive of the risk-based initiative, this type of response is inconsistent with their position in our view.
Response: The Cost Effective Analysis Process (CEAP) in the draft 3 posting of PRC-025-1 was an initial pilot of the program for only Phase II of the CEAP. The drafting team was provided summary information which did not reveal substantive reasons for changing the way the team developed PRC-025-1. Please see the Pilot CEAP Report on the Project 2010-13.2 project page (http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx). No change made. Also, NERC Compliance provided the industry comments to the drafting team from the RSAW which was posted contemporaneously with the draft 3 posting of PRC-025-1. Revisions made to the RSAW were provided to NERC Compliance for consideration and reposting; however, NERC Compliance elected to wait as they are currently working toward a more defined process for RSAW posting and commenting. No change made.		
Entergy Services, Inc. (Transmission)	Yes	The implementation plan may be challenging to meet and an alternative implementation plan may need to be provided based on the population of load-responsive protective relays determined affected by this standard and the subset of which that will require replacement relays. Additional resources will be required to (1) determine the population of load-responsive relays at each generating station,

Organization	Yes or No	Question 5 Comment
		(2) determine the settings of the existing load-responsive relays, (3) calculate load-responsive relay settings per the reliability standard, (4) compare the existing load-responsive relay settings to the calculated load-responsive relay settings to determine the population which are acceptable as-is, the population that require a settings change, and the population that requires replacement, (5) schedule the population of load-responsive relays for settings change, (6) order replacement load-responsive relays for the population determined incapable of meeting the reliability standard and schedule relay replacement. The resulting calculations and set-point datasheets will form the basis for the load-responsive relay settings and evidence for meeting the standard's requirements.
Response: The drafting team thanks you for your comments and contends that the Implementation Plan establishes the deadlines by which the standards must be implemented. Individual steps to achieve implementation are left to the entity to determine and manage. No change made.		
Public Service Enterprise Group	Yes	The SDT needs to confirm that UATs that are energized from the system (not the GSU) at high-side voltages that are below 100 kV are part of the BES before imposing standards on UAT load-responsive relay settings.
Response: The drafting team thanks you for your comments and notes that NERC Reliability Standards may be applicable to equipment that is not part of the BES if necessary to support reliable operation of the bulk power system. No change made.		
Seminole Electric Cooperative Inc.	Yes	Seminole Electric reasons that the NERC SDT has not provided sufficient evidence to warrant a High VRF and a Severe VSL for penalties associated with proposed Standard PRC-025-1.
Response: The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF		

Organization	Yes or No	Question 5 Comment
Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also contends that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. No change made.		
Flathead Electric Cooperative	Yes	Do not support including Elements utilized in the aggregation of dispersed power producing resources. This seems to have the potential to rope very small generators into significant compliance burdens for very little reliability benefit.
Response: The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made.		
Southwest Power Pool	Yes	For the sake of clarity, I would suggest adding the phrase 'to the generator' at the end of the Purpose of PRC-025-1. This is implied in the existing language but it wouldn't hurt to add this and specifically indicate what damage you're referring to. **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. For consistency within the requirements and between the requirement and corresponding measure in this situation, please add 'Each' at the beginning of Requirement R8. This makes R8 consistent with the rest of the requirements and with

Organization	Yes or No	Question 5 Comment
		Measure M8. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Kansas City Power and Light	Yes	Generators and Generator step up transformers are critical elements of the BES and have very long lead times for replacement or major repair. However, the Transmission Relay load ability standard has less stringent load ability requirements than the Generator load ability standard. Transmission lines are allowed to trip at 150% of four hour rating or 115% of 15 minute rating. We do not understand the newly added portion of the Exceptions of PRC-025-1 why is there only the option of a specific curve type specified for the Generator. There is no exception available for the GSU or Aux Transformers therefore the GSU and Aux transformers that would allow them to be set like large auto transformers it is not our belief that these transformers should be required to be set with more Stringent settings. We believe that these transformers should be set similar to the large auto transformers.
Response: The drafting team thanks you for your comment and notes that Exclusion #7 addresses transformers and is not limited to only GSUs. No change made. This exclusion is different than Exclusion #6 (applicable to generators) to reflect the differences in thermal overload capability. The drafting team asserts the time frames in these exclusions are therefore appropriate. No change made.		
MRO NERC Standards		The NSRF remains concerned that the proposed calculations for the distance relays will

Organization	Yes or No	Question 5 Comment
Review Forum		adversely affect reliability of the BES by requiring generators to pull back distance reaches too far which could lead to reduced rely coverage (at least for backup relaying) or longer delays for coordination. Some sample calculations performed by NSRF members show that distance reaches need to be pulled back more than 30%. The NSRF members believe that this is most likely due to the more conservative relay load limit angle calculations at 30 degrees rather than former MidContinent Area Power Pool (MAPP) criteria which used line Maximum Torque Angle calculations which typically averaged near 70 - 85 degrees. Sample MAPP Relay Load Limit Calculation: (0.85*kV)^2 / (Z1max*cos(max torque angle - line power factor angle)NSRF sample calculations show that many generators may require 21 distance setting changes based upon this proposed standard, potentially resulting in potential reductions of relay backup coverage for lines leaving some generating stations. This will put a much higher risk and responsibility on the TO too have extremely reliable protection for the lines. We will no longer be able to trip the generator off in a backup mode if the TO does not clear the phase fault at end of line. This appears to conflict with R1, unless the standard is mandating the installation of additional equipment such as redundant relays systems to maintain reliable fault protection. The NSRF would ask the NERC Standard drafting team to work with NSRF members to help verify the basis for the new calculations and if this does in fact reduce relay coverage or require entities to install additional relaying to maintain system reliability as mandated in R1.

Response: The drafting team thanks you for your comments and notes the basis for the calculations for the generator protective relays in proposed PRC-025-1 is well established by observed behavior during disturbances and by simulations, and the observed behavior verifies the simulations. The various options (…a, …b, and …c) represent varying degrees of calculation complexity, wherein the most conservative criterion represents a very simple calculation, and the complexity increases as the criteria becomes less conservative. No change made.

The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase

Organization	Yes or No	Question 5 Comment
relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made.		
Texas Reliability Entity		Texas RE generally supports this standard as written, other than the use of the term *Regional Reliability Organization* in Table 1 as described above. Our other comments are provided for consideration by the drafting team.
Response: The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made.		
Exelon and its affiliates		The Constellation Energy Nuclear Generation (CENG) NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." Section 3.2.3 of PRC-025-1 requires clarification simply because the Unit Auxiliary Transformers (UAT's) are not necessarily directly connected to the generator, but there are indirect link to the generator operation. The UAT's are ok to be included to the applicability of this standard, but section 3.2.3 could use more detailed explanation. Moreover, the webinar on 5/15/13 pointed out that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power drawn of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in

Organization	Yes or No	Question 5 Comment
		practice. CENG state that Facilities, UAT's in Section 3.2.3 is appropriate to include it, but there need to be a specific explanation as to the affect of MW due to grid disturbance affect the generator output. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT's lack of impact on generator loadability should be considered.
Response: The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
Consumers Energy	Yes	Page 3 of 20, 3.2: Blackstart Resources that would not otherwise be defined as part of the BES should not be included in the Facilities. Although voltage swings will occur during restarting of the system, the detailed planning to control the electrical paths and the placement of operating personnel to key substation locations preclude the need for loadability criteria for these small generators. Blackstart Resources should be removed from the list of Facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made.

Organization	Yes or No	Question 5 Comment
		Page 8 of 20, Exceptions: The Drafting Team has added one bullet item to and modified one in the list of Exceptions. The first one recognizes the need to operate within generator short time capabilities and is acceptable. The second exclusion attempts to place an operator response time of 15 minutes or greater to a transformer overload condition. While a system disturbance may continue for extended periods, we believe that the 15 minute time frame far exceeds the practical relay operate time of standard electromechanical, static or digital protective relays. The operate time characteristics for most relays, as drawn on the manufacturers' time-current curves, are much faster than 15 minutes. Traditional relay curves are drawn to begin at 1.5 times pickup. The maximum relay operate times at that defined relay pickup is typically in the 2-5 minute range. Considering that the relay curves do not extend beyond a few minutes, a time specification beyond 5 minutes is unrealistic. The wording of the last exception should be changed to exclude: "Protection systems that detect transformer overloads and are designed to respond in time periods which are greater than 2 minutes" **Response:** The drafting team intends to exempt schemes that are explicitly designed for overload protection, for which characteristics would be defined for the time period in the bullet. Load-responsive relays that respond otherwise must meet the criteria in Table 1. The proposed change to 2 minutes in the referenced exclusion may not be sufficient to allow the system voltage to recover for the conditions being addressed by this standard. No change made. Page 14-15 of 20, 8a, 8b and 8c: The standard Pickup Setting Criteria for the step-up transformer overcurrent element pickup is stated as 115% of any of three calculated currents. In these cases the step-up transformer can probably withstand the high currents for a short period of time, however all generators cannot be expected to operate up to this percent current. It should be recognized that the control functions set to protect the generator short time capabilities may supersede the operation of the overcurrent element. Therefore any dynamic modeling of a generator must include the excitation limitations. If the overcurrent element is set to operate to protect the generator, then the pickup criteria must be changed to limits of the particular

Organization	Yes or No	Question 5 Comment
		generator. A fourth alternative 8d should be created to recognize generator limits and allow for setting the pickup and timing of the overcurrent element to protect the generator. **Response:** Proposed PRC-025-1 is based on system conditions where the generator is expected to provide full field forcing until such a time as the excitation system controls act to bring the generator back to within its steady state capability curve. Options 8a, 8b, and 8c establish that the GSU shall not trip for the identical conditions for which the generator criteria are established. No change made. Page 17 of 20, 13a and 13b: Unit auxiliary transformers are normally sized to carry all of the station power loads for the expected range of the generator operating voltage. A transformer high side overcurrent relay should be set to allow the transformer loading, with margin. Since the standard is based upon "widely depressed" system voltage and the standard recognizes that the generator will be supplying VARs to the system, the generator terminal voltage will most likely be at or above rated. The pickup criteria are unnecessarily complicated by the inclusion of 13b. We recommend retaining 13a and the removal of 13b. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. The UAT can be connected at a variety of points; for system-connected UAT, the UAT primary winding will see approximately 0.85 p.u. voltage; for unit-connected UAT, the drafting team estimates that this voltage will be 0.9 to 0.95 p.u. voltage. The drafting team has proposed a 150% margin for these relays rather than requiring an analysis of the connected loads for depressed voltage; the margin includes consideration for the increased current called for by these loads as well as normal relay

Organization	Yes or No	Question 5 Comment
		setting tolerances. Some entities have indicated that 13b may be useful; therefore the drafting team has decided to not remove it. No change made.
Response: The drafting team thanks you for your comments.		

END OF REPORT

Draft 4

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.
7. Draft 3 of the standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013 and a successive ballot in the last ten days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 4 of PRC-025-1, Generator Relay Loadability for a 30-day formal comment period and successive ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and Initial Ballot	January 2013
30-day Formal Comment Period and Successive Ballot	May 2013
30-day Formal Comment Period and Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Relay Loadability**

2. **Number: PRC-025-1**

   Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.2. Facilities: The following Elements associated with Bulk Electric System generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

   3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

4. Background:

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations,

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities shall use one of the following Options 1-19 in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect a generator step-up (GSU) transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant , the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in the table. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full-load current, and prevent operation below 115% of full-load current.
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups those relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Synchronous generators	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Synchronous generators	Phase time overcurrent relay (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Synchronous generators	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts below				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relays will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 7	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generators	Phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[3]	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generators	Phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU If the relay is installed on the generator-side of the GSU transformer use Option 9	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 10	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to asynchronous generators only (including inverter-based installations)	Phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 11	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.
7. Draft 3 of the standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013 and a successive ballot in the last ten days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 4~~2~~ of PRC-025-1, Generator Relay Loadability for a 30~~45~~-day formal comment period and successive~~initial~~ ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and Initial Ballot	January 2013
30-day Formal Comment Period and Successive Ballot	May 2013
30-day Formal Comment Period and Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-1**

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements~~Facilities~~ listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. Facilities:~~Facilities:~~ The following Elements associated with Bulk Electric System generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

3.2.4 Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~**3.2.4** Generator interconnection Facility(ies).~~

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations,

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements~~Facilities~~ listed in 3.2, Facilities shall use one of the following Options 1-19 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect a generator step-up (GSU) transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~a generator interconnection Facility~~, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the ~~generator step-up (~~GSU~~)~~ transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in the table. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

~~Exceptions~~

Any relay elements that are in service only during start up.~~, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:~~

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).~~),~~
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard.~~,~~
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).~~),~~
- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.~~, or~~
- Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full-load current, and ~~supervised to~~ prevent operation below 115% of full-load current.
- Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant).~~generator interconnection Facilities).~~ Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by ~~alternately~~ shading groups those~~of~~ relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded.~~within a similar application.~~ Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Synchronous generators	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[3] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[3]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="6">Synchronous generators</td><td rowspan="5">Phase time overcurrent relay (51V-R) – voltage-restrained</td><td>2a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and
(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">**OR**</td></tr>
<tr><td>2b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and
(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">**OR**</td></tr>
<tr><td>2c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or~~, other entity as specified by the Regional Reliability Organization (RRO),~~ and
(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">**The same application continues on the next page with a different relay type**</td></tr>
<tr><td>Synchronous generators</td><td>Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)</td><td>3</td><td>Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>Voltage control setting shall be set less than 75% of the calculated generator bus voltage</td></tr>
</table>

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
A different application starts below				
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
Generator step-up transformer connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, ~~or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
	high-side of the GSU transformer use Option 14	7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner,~~ or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	use Option 15	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Generator step-up transformer connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	installed on the high-side of the GSU transformer use Option 16	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51) applied at~~that trips~~ the high-side terminals of the UAT, for which operation of the relays will cause the associated generator to trip.~~either directly or via an interposing auxiliary/lockout relay~~	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization (RRO)~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
A different application starts on the next page				
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator interconnection Facilities~~ connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 7	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
	The same application continues on the next page with a different relay type			
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator~~	Phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
~~interconnection Facilities~~ connected to synchronous generators	where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8~~Phase time overcurrent relay (51)~~	15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[3]	Pickup Setting Criteria
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator interconnection Facilities~~ connected to synchronous generators	Phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU If the relay is installed on the generator-side of the GSU transformer use Option 9	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner~~, or other entity as specified by the Regional Reliability Organization (RRO),~~ and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
A different application starts on the next page				
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator interconnection Facilities~~ connected to asynchronous generators only	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 10	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
(including inverter-based installations)	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to asynchronous generators only (including inverter-based installations)	Phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 11~~Phase time overcurrent relay (51)~~	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[3]**	**Pickup Setting Criteria**
Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Implementation Plan

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner, Transmission Owner, or Distribution Provider might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames. One time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays require replacement or removal. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load

encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of proposed PRC-025-1.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner, Transmission Owner, or Distribution Provider will need to: evaluate load-responsive protective relays applied on its Facilities; perform the applicable calculations required by the standard; and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.
9. The Generator Owner, Transmission Owner, and Distribution Provider will need to coordinate activities where multiple owners may need to perform its work under the standard.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

<table>
<tr><th rowspan="2">Requirement</th><th rowspan="2">Applicability</th><th colspan="2">Implementation Date</th></tr>
<tr><th>Jurisdictions where Regulatory Approval is Required</th><th>Jurisdictions where No Regulatory Approval is Required</th></tr>
<tr><td rowspan="2">R1</td><td rowspan="2">Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after applicable regulatory approvals</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities</td></tr>
<tr><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after applicable regulatory approvals</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities</td></tr>
</table>

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including, but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition , shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1 (New)** **R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 (Retirement) R1, Criterion 6. – "Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	

Implementation Plan

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner, Transmission Owner, or Distribution Provider might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames. One time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays require replacement or removal. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load

encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of proposed PRC-025-1.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner, Transmission Owner, or Distribution Provider will need to: evaluate load-responsive protective relays applied on its Facilities; perform the applicable calculations required by the standard; and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.
9. The Generator Owner, Transmission Owner, and Distribution Provider will need to coordinate activities where multiple owners may need to perform its work under the standard.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

~~None.~~PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day ~~48~~60 months after applicable regulatory approvals	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day ~~48~~60 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day ~~72~~84 months after applicable regulatory approvals	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day ~~72~~84 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of ~~the Generator Owner~~itself including, but not limited to changes in NERC Registration Criteria~~,~~ or Bulk Electric System (BES) definition ~~, or any other non-Generator Owner action~~, shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day ~~48~~60 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day ~~48~~60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day ~~72~~84 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day ~~72~~84 months beyond the date the load-responsive protective relays become applicable to the standard

~~**Transition to Using Capability Reported to the Transmission Planner**~~

~~Reliability Standard PRC-025-1 requires the Generator Owner to use “Real Power output – 100% of the gross MW capability reported to the Transmission Planner or other entities as specified by the Regional Reliability Organization.” PRC-025-1 includes the “Transmission Planner” to comport with the functional entity that receives the report of the Generator Owner’s gross Real Power capability pursuant to Reliability Standard MOD-025-2, which combines Reliability Standards MOD-024-1 and MOD-025-1.~~

~~Because Reliability Standards MOD-024-1 and MOD-025-1 require the Generator Owner to follow its Regional Reliability Organization’s procedures for reporting its gross Real and Reactive Power capability, respectively, Reliability Standard PRC-025-1 also includes the phrase “other entities as specified by the Regional Reliability Organization” so that the Generator Owner can remain compliant with PRC-025-1 and both MOD-024-1 and MOD-025-1 during the implementation period for MOD-025-2. This construction avoids a reliability gap and ambiguity within the PRC-025-1 standard regarding the value (gross Real Power capability) that is reported during the extended implementation plan for MOD-025-2.~~

~~Upon retirement of MOD-024-1 and MOD-025-1 and full compliance with MOD-025-2, entities will be reporting solely to the Transmission Planner. At that time, the reference to “other entities as specified by the Regional Reliability Organization” will be removed from PRC-025-1 since it will no longer be necessary or utilized by any functional entities following full implementation of MOD-025-2.~~

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified ~~in **bold blue with underlining for additions** and for **deletions in bold red with a strikeout**~~by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1 (New)** **R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 (Retirement) R1, Criterion 6. – "Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.

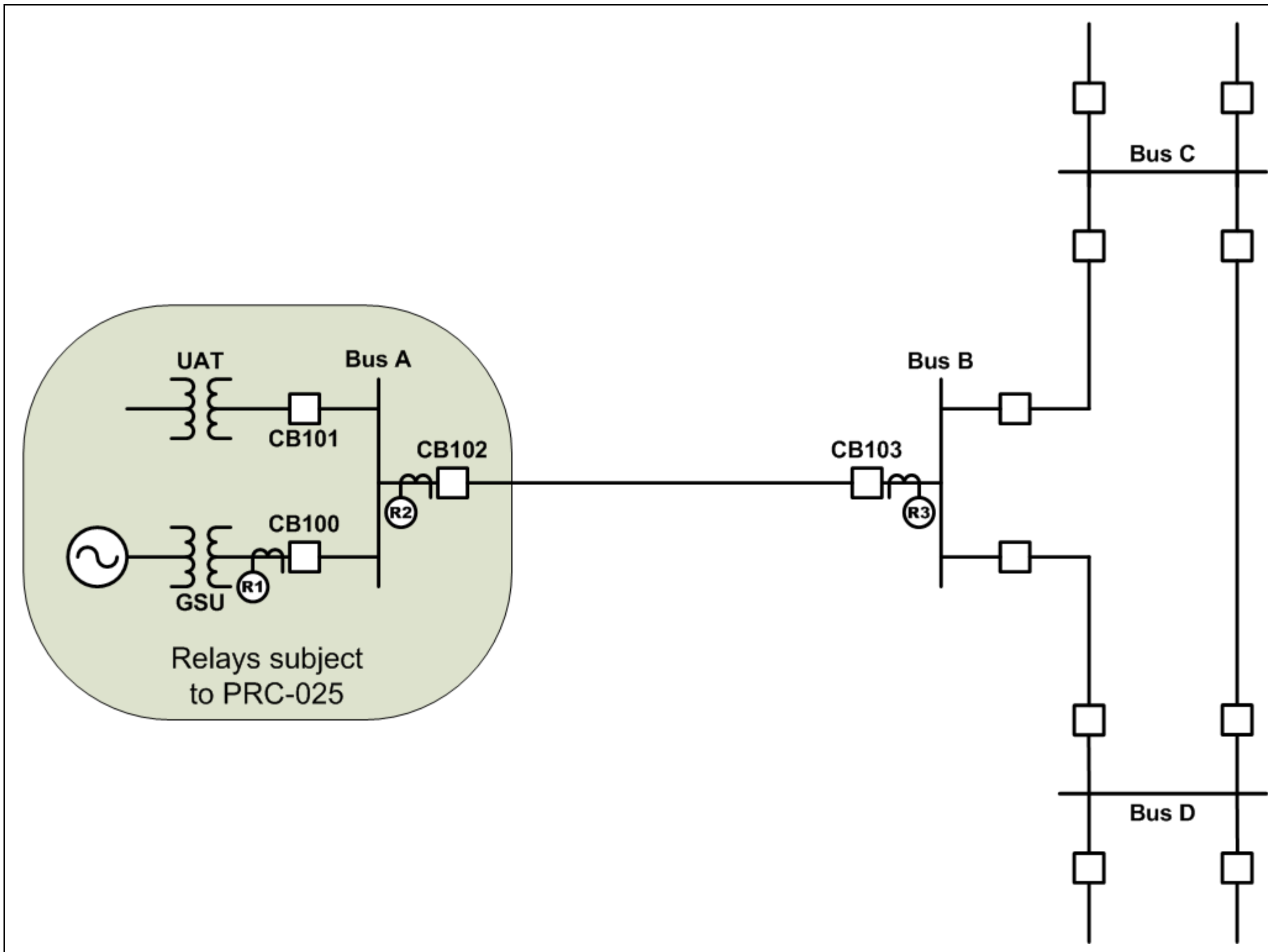


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.

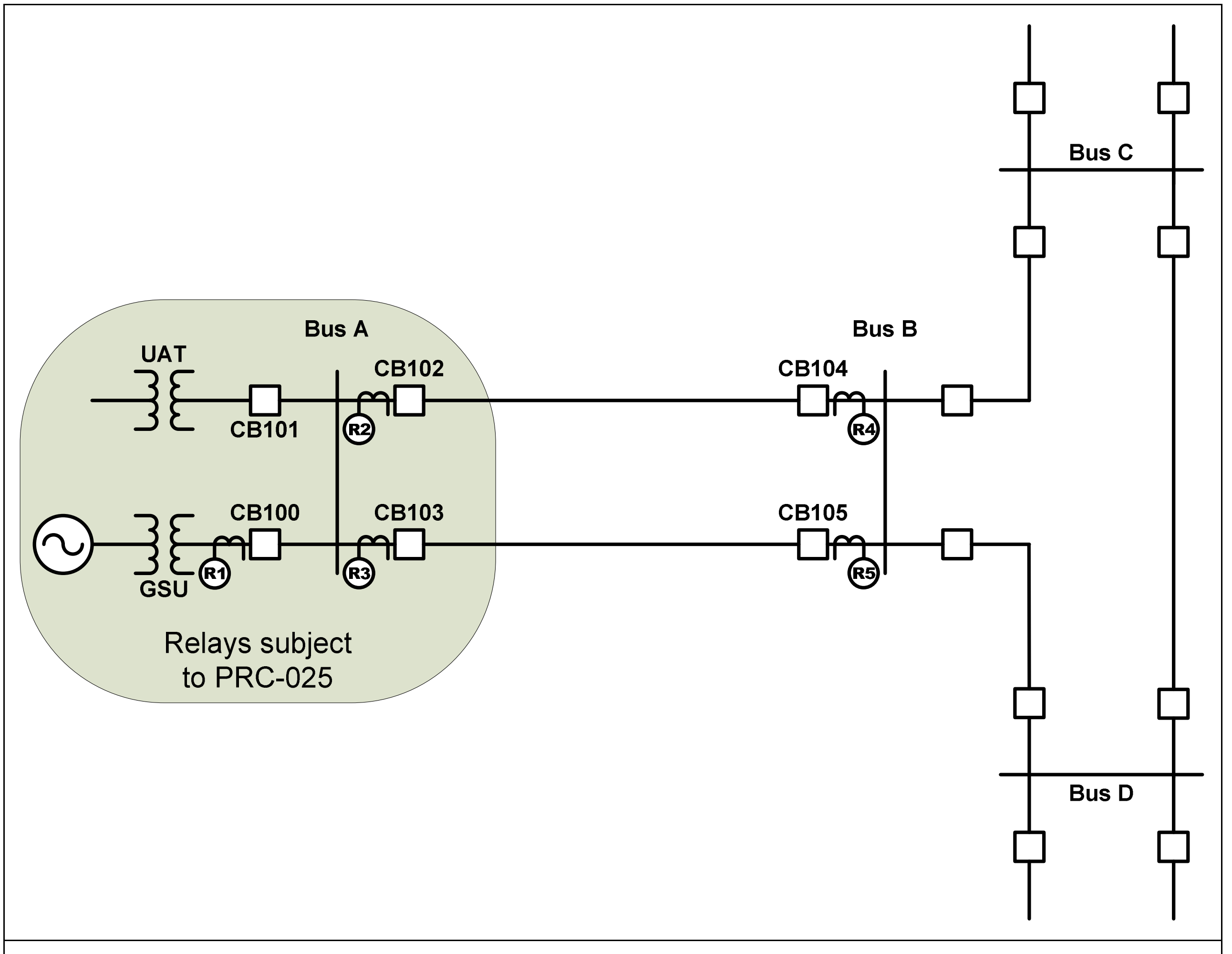


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

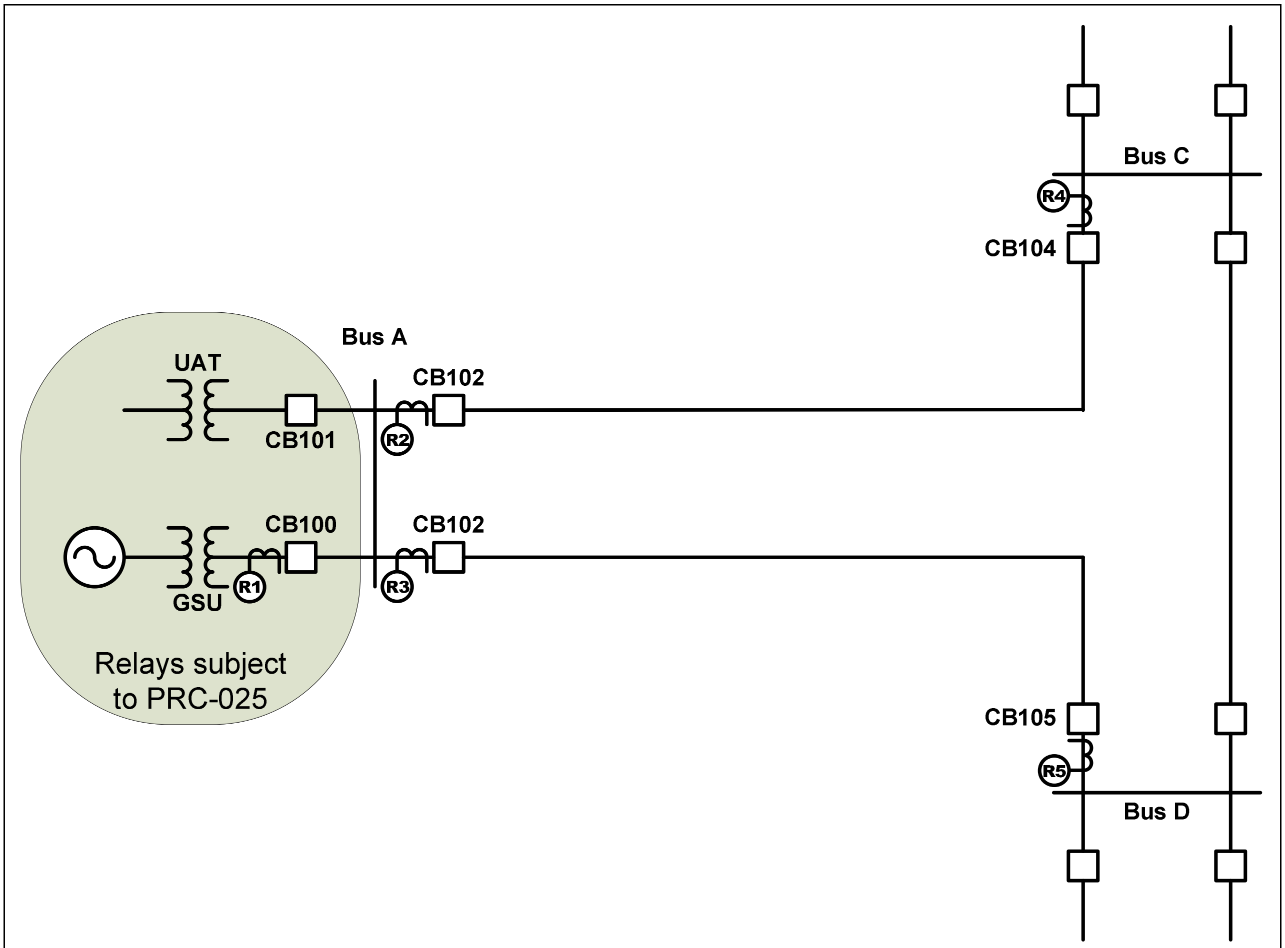


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column “Pickup Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics.

The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective elements associated with the facility are included in PRC -025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-1. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-1. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the GSU transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the GSU transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared***

by the transmission line breakers. *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

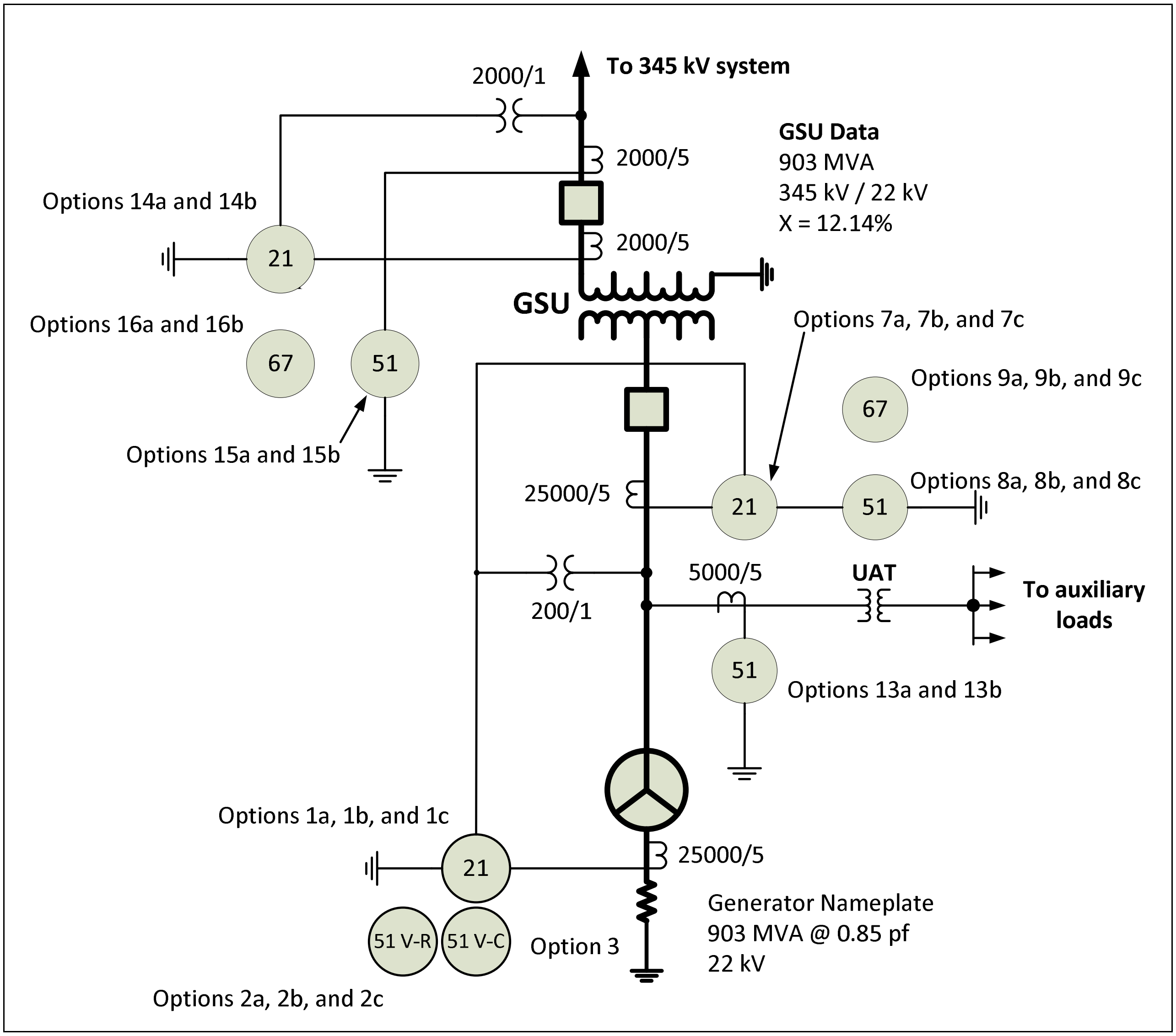


Figure 4. Relay Connection for corresponding synchronous options.

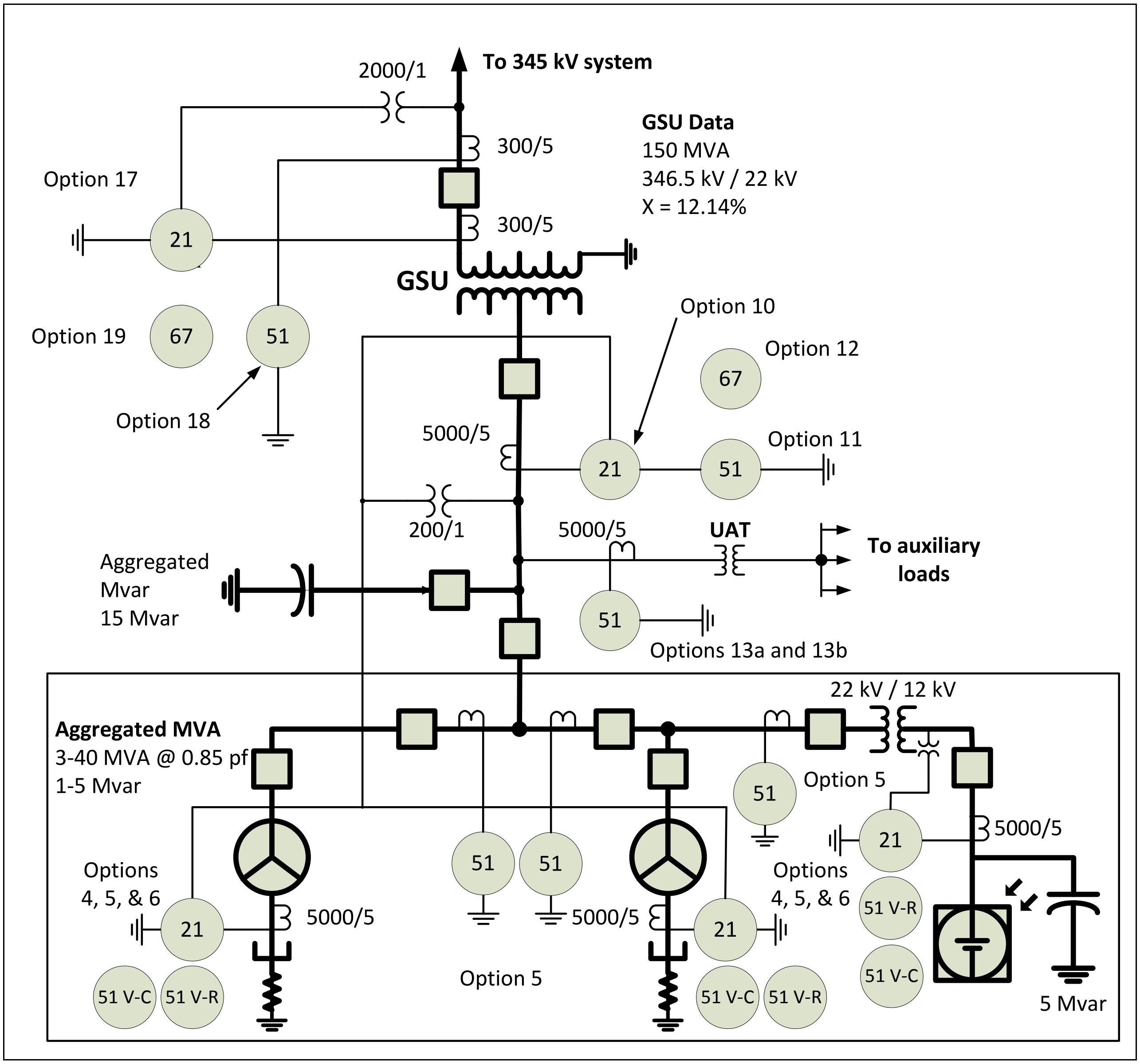


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled").

These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150

percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for GSU transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU transformer. Where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase time overcurrent relaying applied to the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

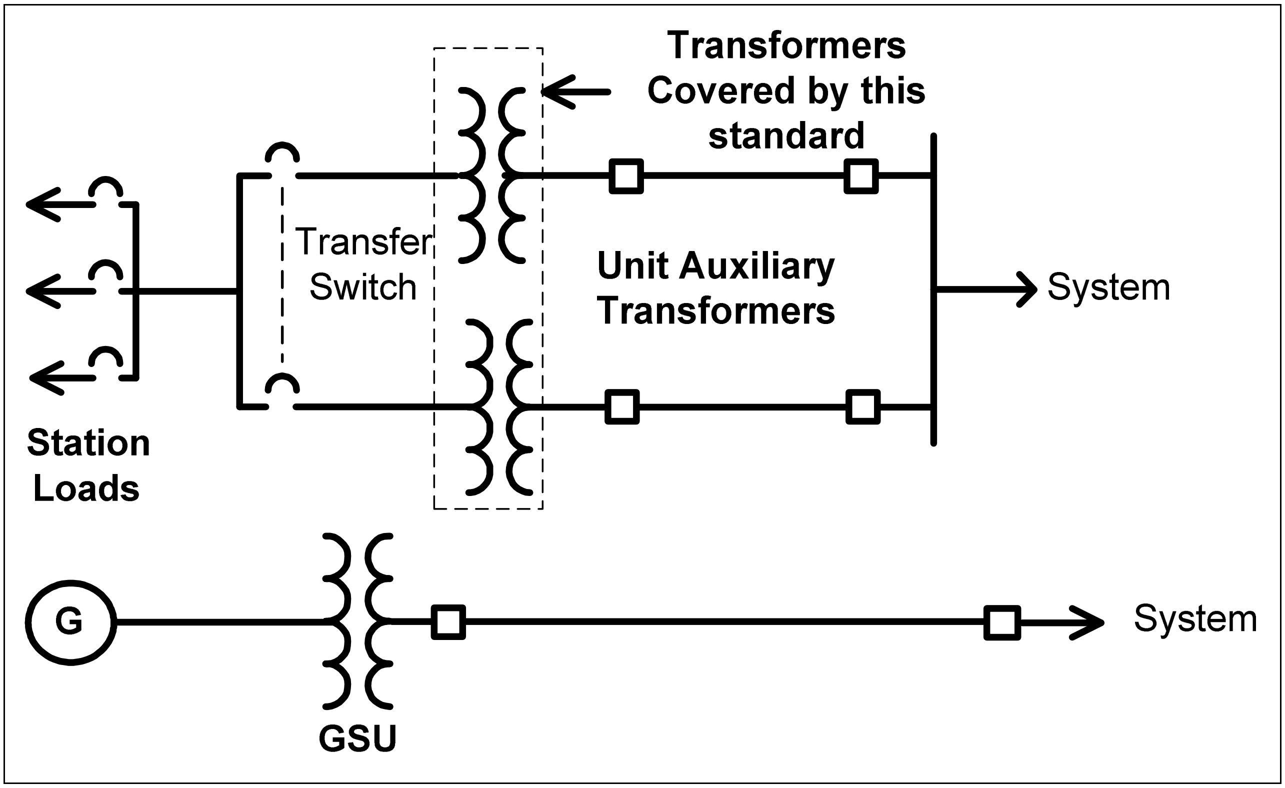


Figure-6 – Auxiliary Power System (independent from generator).

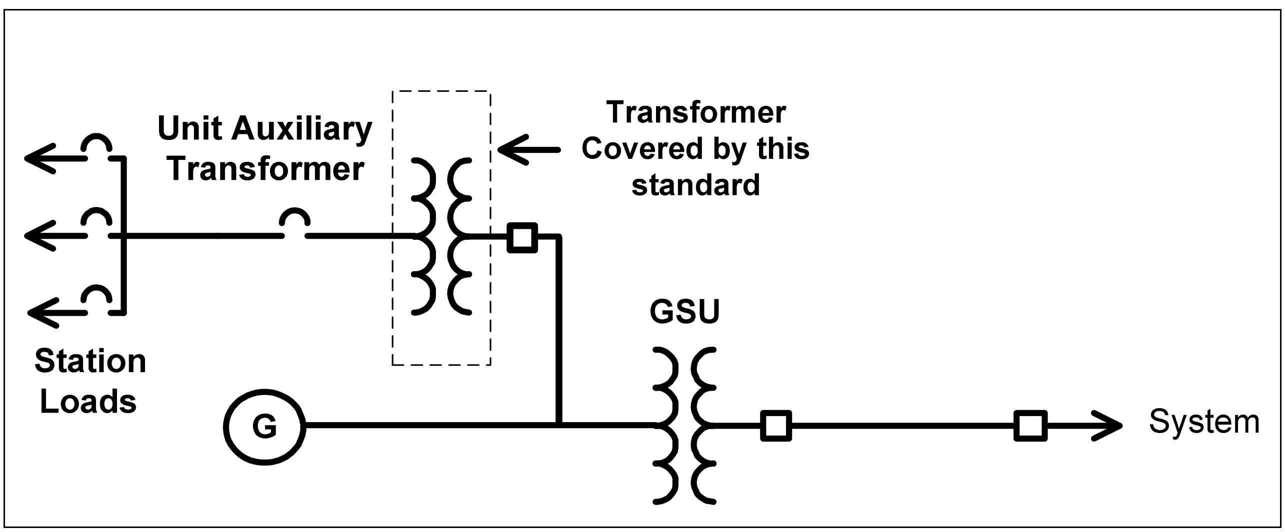


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting pickup compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or

dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$

Example Calculations.	
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a
Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\,\Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\,\Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\,\Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\,\Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\,\Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\dfrac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\dfrac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = 6.7°$$

Eq. (15)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 1b and 7b

Apparent power (S):

Eq. (19) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7^\circ\ MVA$$

Primary impedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7^\circ\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7^\circ\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.356\angle 58.7^\circ\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7^\circ\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7^\circ\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{8.900\angle 58.7^\circ\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7^\circ\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (23) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0^\circ - 58.7^\circ)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < \ 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

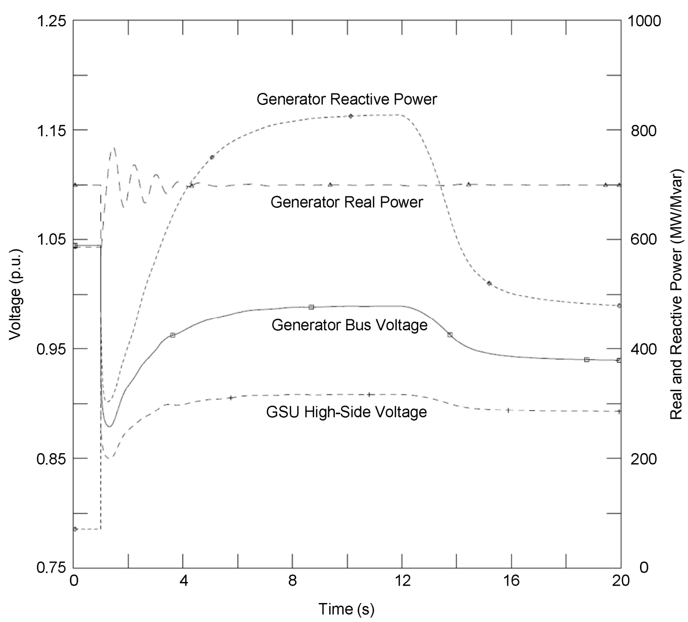
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Example Calculations: Options 1c and 7c

Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8\angle 49.8°\ MVA$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$

$Z_{pri} = 0.437\angle 49.8°\ \Omega$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$

$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$

$Z_{sec} = 10.92\angle 49.8°\ \Omega$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$

$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$

$\theta_{transient\ load\ angle} = 49.8°$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$

Example Calculations: Options 1c and 7c

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 2a

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

In this simulation the following values are derived:

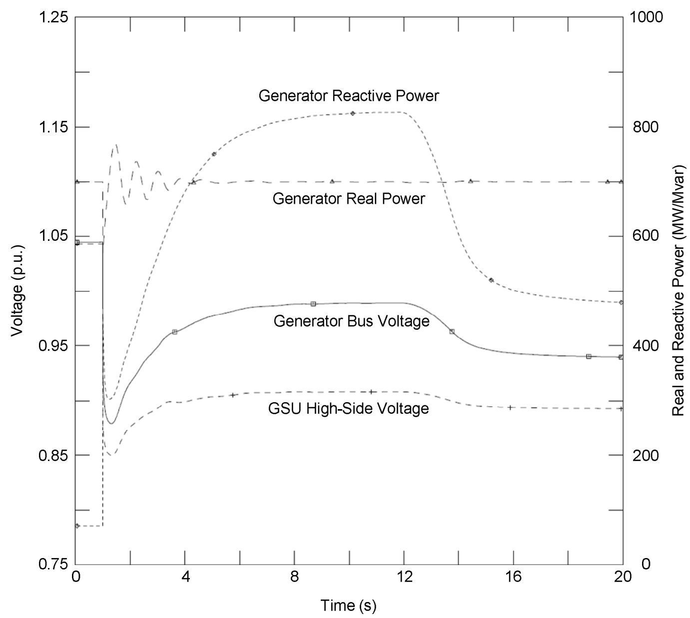
$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

Example Calculations: Option 2c

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Option 2c

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 5.758\ A \times 1.15$

$I_{\sec limit} > 6.622\ A$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$V_{gen} = 21.9\ kV$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$V_{setting} < 21.9\ kV \ \times 0.75$

$V_{setting} < 16.429\ kV$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = \ GEN_{Asych\_nameplate} \times pf$

$P = 40\ MVA \ \times 0.85$

$P = 34.0\ MW$

Example Calculations: Option 4

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

Example Calculations: Option 4

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\,\Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\,\Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\,\Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\,\Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\,\Omega$$

Example Calculations: Option 5

This represents the calculation for three asynchronous generators applying a phase time overcurrent (51V-R) – voltage-restrained relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (71) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{synch}):

Eq. (72) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (73) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (74) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (75) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (76) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

Example Calculations: Options 7a and 10

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (77) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (78) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8^\circ\ MVA$$

Primary impedance (Z_{pri}):

Eq. (79) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8^\circ\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8^\circ\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (80) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8^\circ\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8^\circ\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8^\circ\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 85 to satisfy the margin requirements in Options 7a and 10:

Eq. (81) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (82) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} <\ 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $\text{GEN}_{\text{Synch\_nameplate}}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (83) $$P =\ GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (84) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Options 8a and 9a

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (85) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (86) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (87) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (88) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (89) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (90) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (91) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (92) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (93) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (94) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Example Calculations: Options 8b and 9b

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (95) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (96) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (97) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (98) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (99) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (100) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Primary current (I_{pri}):

Eq. (101) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\, MVA}{1.73 \times 21.90\, kV}$$

$$I_{pri} = 35553\, A$$

Secondary current (I_{sec}):

Eq. (102) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\, A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\, A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (103) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.111\, A \times 1.15$$

$$I_{\sec limit} > 8.178\, A$$

Example Calculations: Options 8a, 9a, 11, and 12
This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (104) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (105) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (106) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (107) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (108) $I_{pri-sync} = \dfrac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (109) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (110) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (111) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (112) $S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (113) $I_{pri-async} = \dfrac{S_{Asych}}{\sqrt{3} \times V_{gen}}$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (114) $I_{sec} = \dfrac{I_{pri-sync}}{CT_{ratio}} + \dfrac{I_{pri-async}}{CT_{ratio}}$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061\angle -58.7°\,A}{\frac{25000}{5}} + \frac{4755\angle -39.2°\,A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\,A$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 94 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 98:

Eq. (115) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\,A \times 1.00$$

$$I_{\sec limit} > 9.514\angle -56.8°\,A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

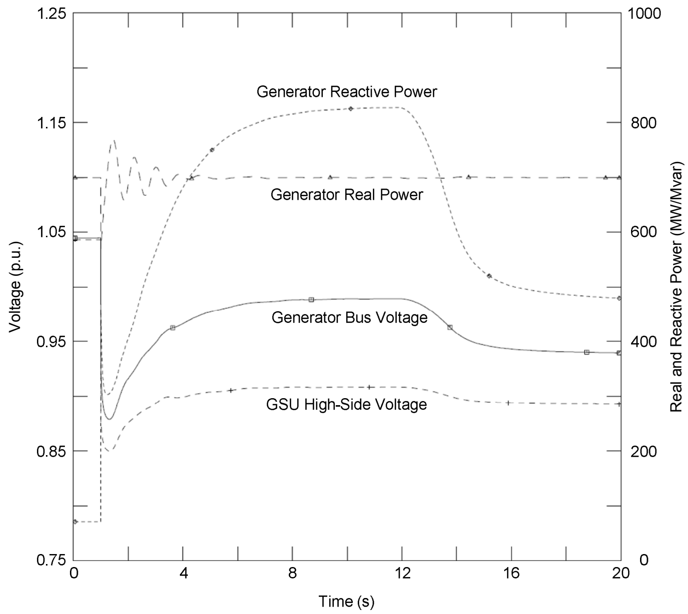
$$Q = 827.4\,Mvar$$

$$V_{bus} = 0.989 \times V_{gen} = 21.76\,kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\,MW$$

Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (116) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (117) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (118) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Options 8c and 9c

To satisfy the 115% margin in Options 8c and 9c:

Eq. (119) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10

This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (120) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (121) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (122) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (123) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2^\circ\ MVA$$

Example Calculations: Option10

Primary impedance (Z_{pri}):

Eq. (124) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (125) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (126) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (127) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < \ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (128) $P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (129) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (130) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (131) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (132) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (133) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2° \, A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \, A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (134) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \, A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \, A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (135) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \, MVA}{1.73 \times 13.8 \, kV}$$

$$I_{pri} = 2510.2 \, A$$

Secondary current (I_{sec}):

Eq. (136) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \, A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (137) $$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (138) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (139) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (140) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (141) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77^\circ\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77^\circ$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (142) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (143) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (144) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (145) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

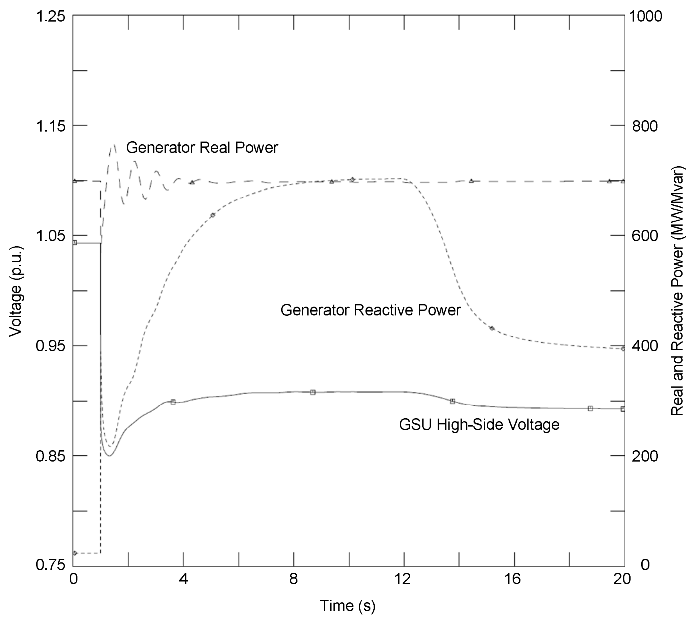
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (146) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Example Calculations: Option 14b

Primary impedance (Z_{pri}):

Eq. (147) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (148) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (149) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (150) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15a represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.

Real Power output (P):

Eq. (151) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (152) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (153) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (154) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8^\circ\ MVA$$

Primary current (I_{pri}):

Eq. (155) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8^\circ\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle - 52.8°\,A$$

Secondary current (I_{sec}):

Eq. (156) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle - 52.8°\,A$$

To satisfy the 115% margin in Options 15a and 15b:

Eq. (157) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle - 52.8°\,A \times 1.15$$

$$I_{\sec limit} > 6.56\angle - 52.8°\,A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15b represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

In this simulation the following values are derived:

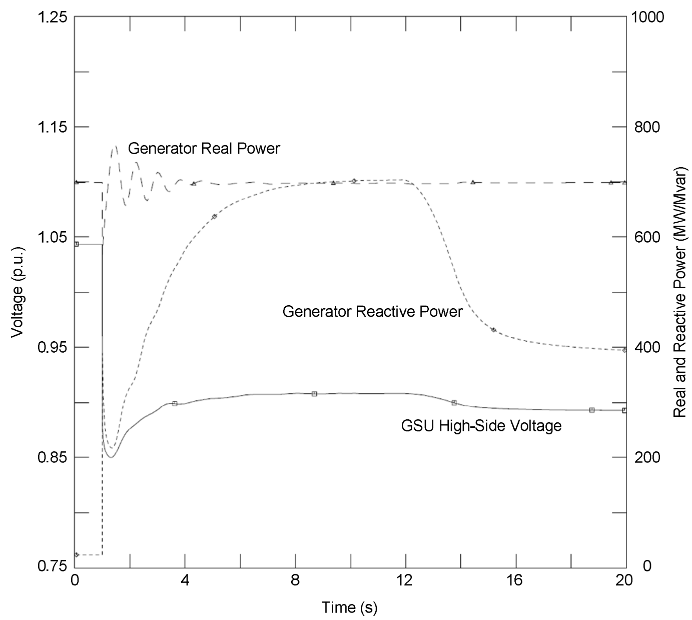
$$Q = 703.6\,Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\,kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

Example Calculations: Options 15b and 16b

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (158) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (159) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (160) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\ A$$

Example Calculations: Options 15b and 16b

To satisfy the 115% margin in Options 15b and 16b:

Eq. (161) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 4.578\angle -45.1° A \times 1.15$

$I_{\sec limit} > 5.265\angle -45.1° A$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (162) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q):

Eq. (163) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (164) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$V_{gen} = 1.0 \times 345\ kV$

$V_{gen} = 345.0\ kV$

Apparent power (S):

Eq. (165) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Example Calculations: Option 17

Primary impedance (Z_{pri}):

Eq. (166) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (167) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (168) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (169) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19
Option 18 represents the calculation for three generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, Option 19 may also be applied here for the phase directional time overcurrent relays (67) directional toward the Transmission system for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (170) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (171) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (172) $V_{nom} = 1.0\ p.u. \times V_{nom}$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (173) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (174) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5 \angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (175) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (176) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase~~The term~~, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1:~~,~~ Relay Settings, Table 1:~~,~~ Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, ~~generator step-up (~~GSU~~)~~ transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to~~) and, where applicable,~~ the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant,~~Generator Owner's generator interconnection Facility~~ and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU~~generator step-up~~ transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "~~refers to these Facilities as "~~generator interconnection Facility"~~(ies)"~~ consistent with the work of ~~the~~ Project 2010-07 (Generator Requirements at the Transmission Interface), because~~) drafting team. The following three figures clarify various considerations regarding~~ the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.

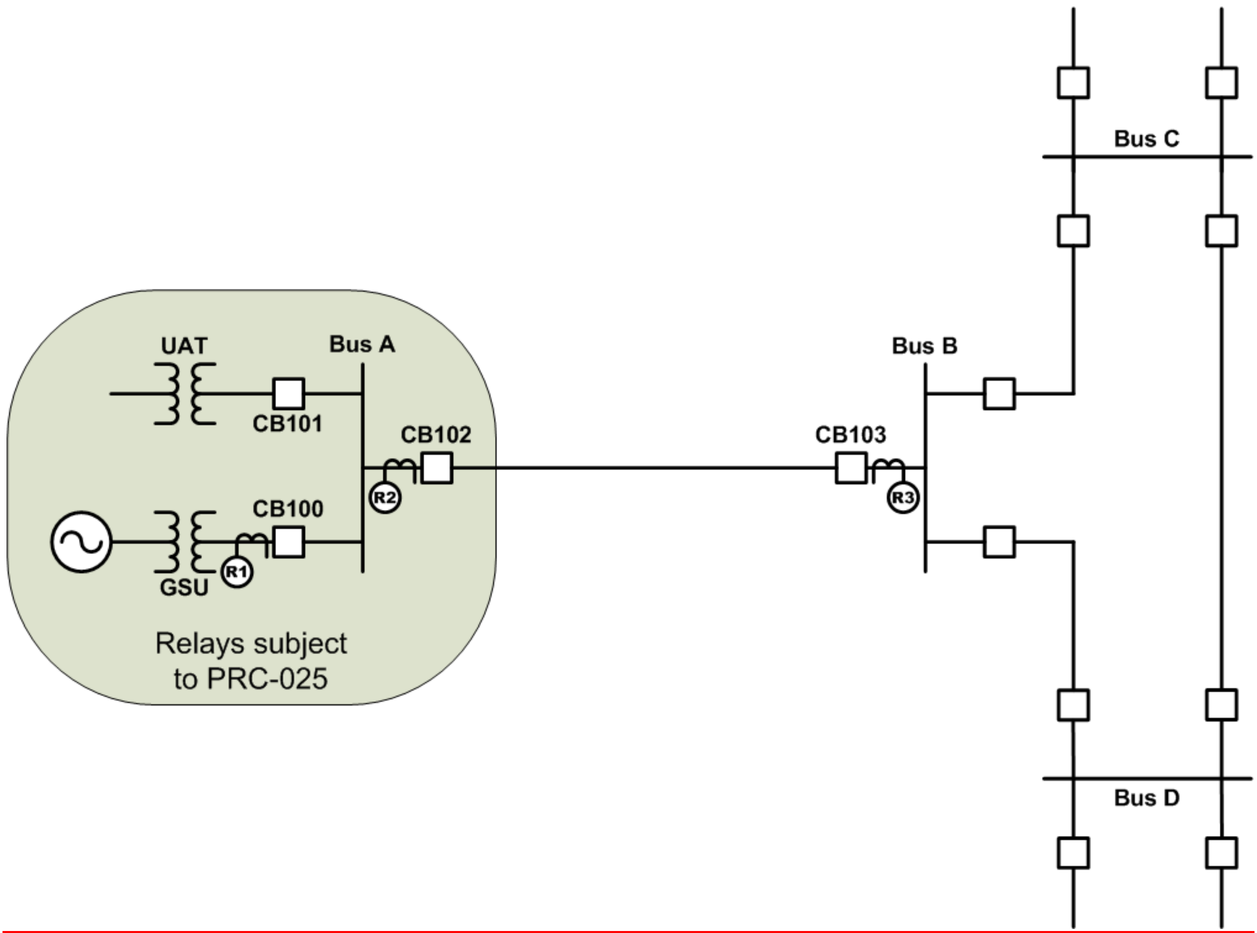


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.

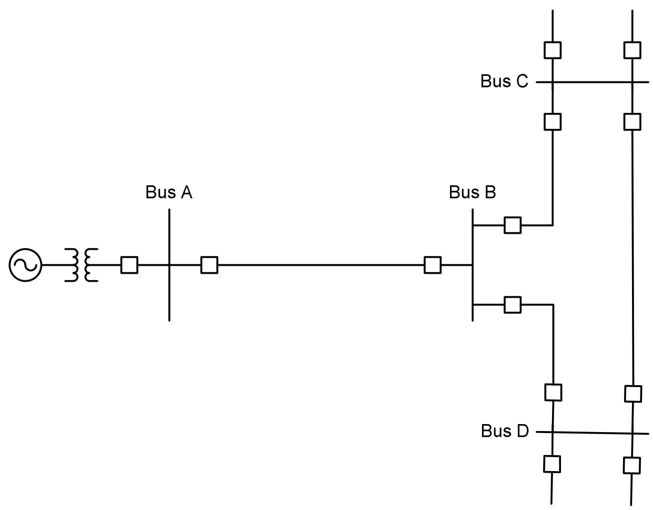
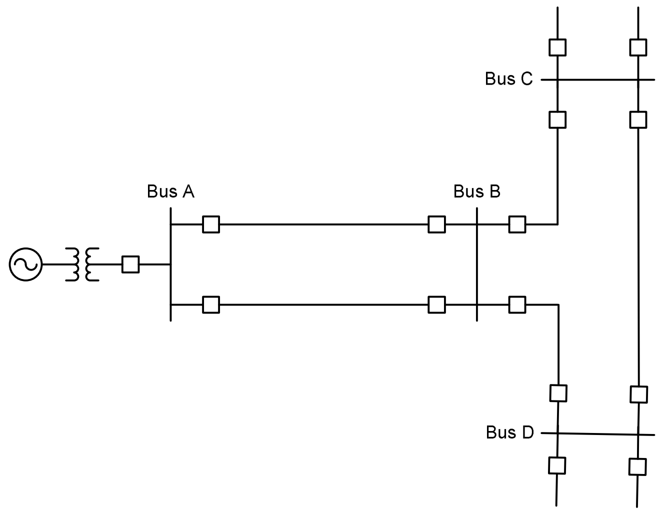


Figure 2. Generation exported through multiple radial lines.~~**Figure 1.** The line from Bus A to Bus B represents a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider or Transmission Owner owns these relays, they are responsible for them under PRC-023.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.



~~**Figure 2.** The parallel lines from Bus A to Bus B together represent a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider, Generator Owner, or Transmission Owner owns these relays, they are responsible for them under PRC-023.~~

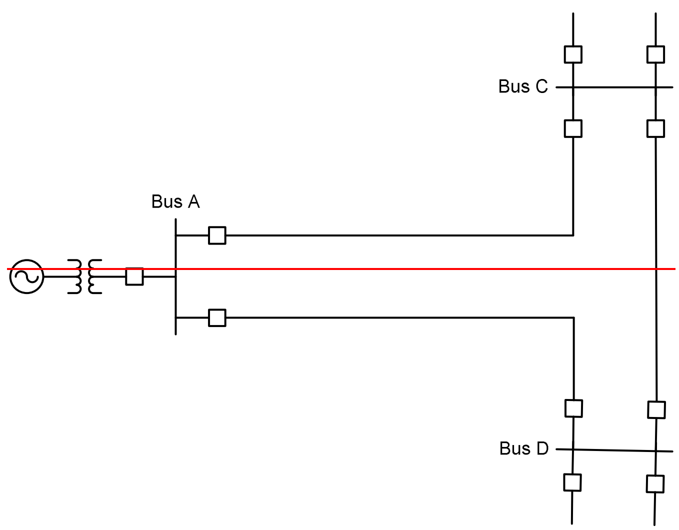


Figure 3. Generation exported through a network.~~**Figure 3.** Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as generator interconnection Facilities. In this case, the Distribution Provider or Transmission Owner would be responsible for the load-responsive protective relays at the terminals under PRC-023.~~

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs~~unit auxiliary transformers (UAT)~~ that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT~~unit auxiliary transformer~~(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU~~generator step-up~~ transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column "Pickup Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU~~generator step-up~~ transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective elements associated with the facility are included in PRC -025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-1. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-1. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive

Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated ~~megawatts (~~MW.~~).~~

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1~~,~~ (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19)~~),~~ for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the GSU~~generator step-up~~ transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the GSU~~generator step-up~~ transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner.~~ or other entity as specified by the Regional Reliability Organization.~~ The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU~~generator step-up~~ transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial*

> *coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator ~~megavoltampere (~~MVA~~)~~ rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU~~generator step-up~~ transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the

Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU~~generator step-up~~ transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

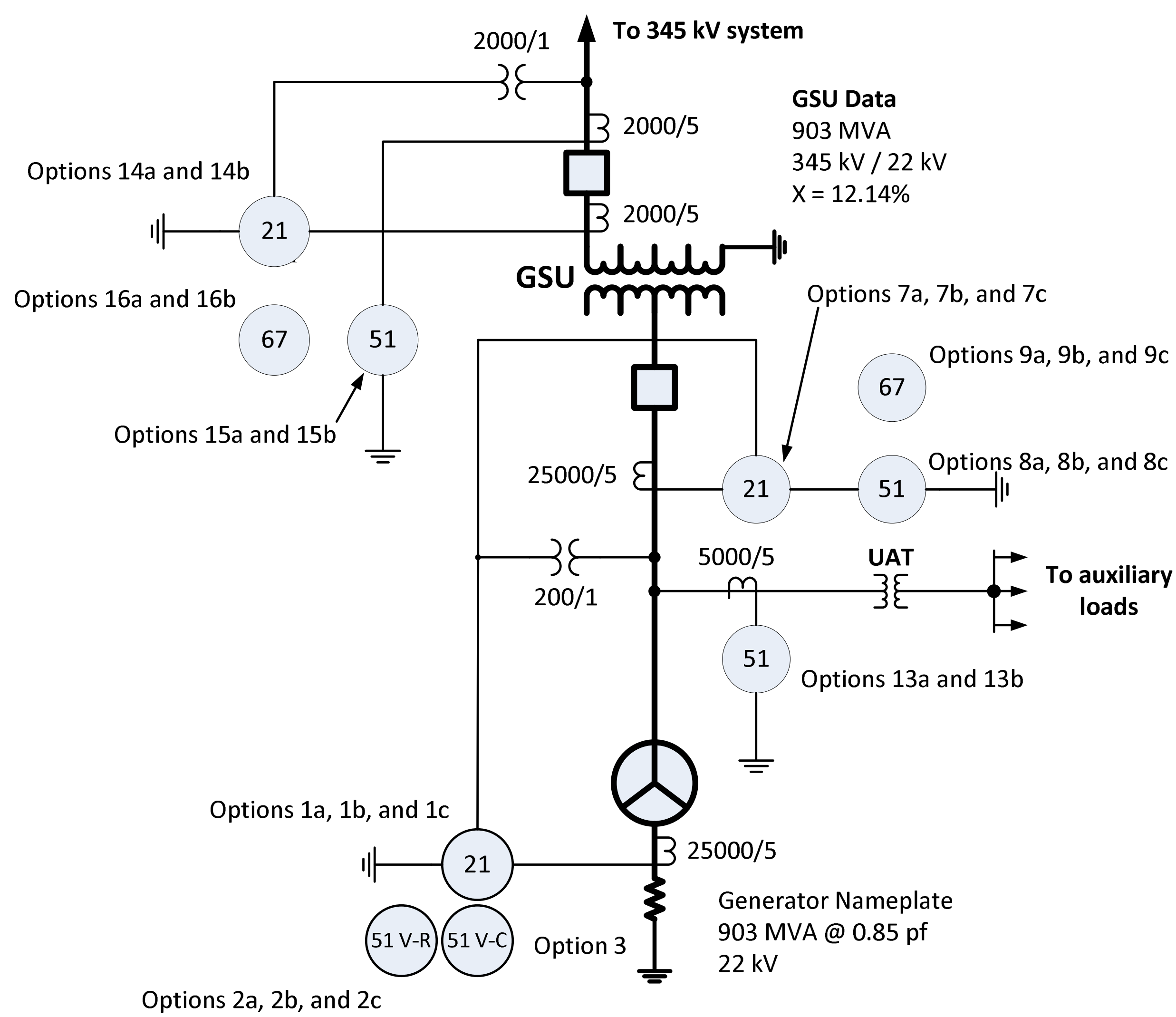


Figure 4. Relay Connection for corresponding synchronous options.

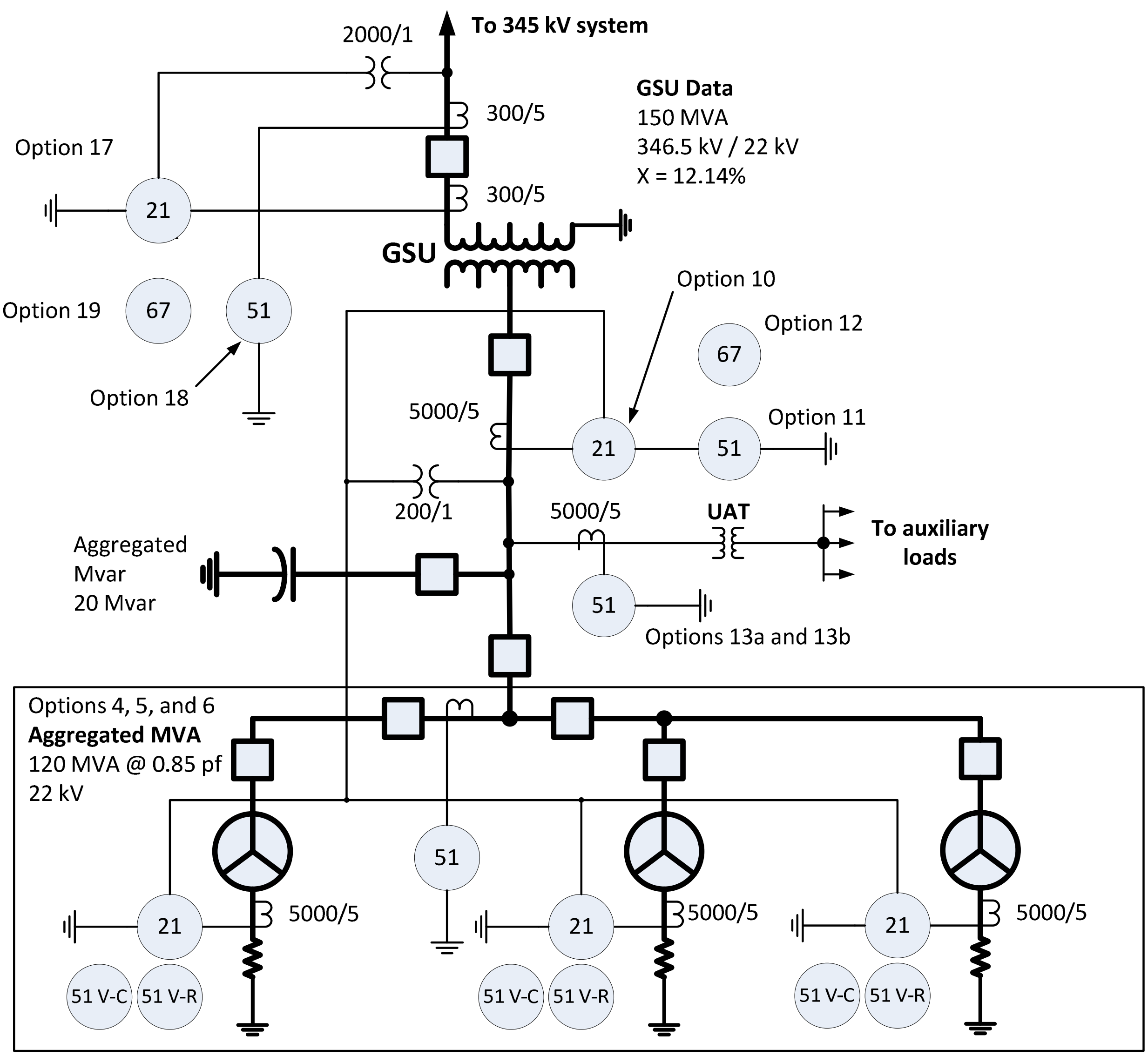


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the

GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The voltage drop across the GSU~~generator step-up~~ transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer and accounts for the turns ratio and impedance.~~, of the generator step-up transformer.~~ The actual generator bus voltage may be higher depending on the GSU~~generator step-up~~ transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115percent~~115%~~ of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The voltage drop across the GSU~~generator step-up~~ transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer and accounts for the turns ratio and impedance.~~, of the generator step-up transformer.~~ The actual generator bus voltage may be higher depending on the GSU~~generator step-up~~ transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU~~generator step-up~~ transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU~~generator step-up~~ transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU~~generator step-up~~ transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the GSU~~generator step-up~~ transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The voltage drop across the GSU~~generator step-up~~ transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer and accounts for the turns ratio and impedance.~~, of the generator step-up transformer.~~ The actual generator bus voltage may be higher depending on the GSU~~generator step-up~~ transformer impedance and the actual Reactive Power

achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU~~generator step-up~~ transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU~~generator step-up~~ transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The voltage drop across the GSU~~generator step-up~~ transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer and accounts for the turns ratio and impedance.~~ of the generator step-up transformer.~~ The actual generator bus voltage may be higher depending on the GSU~~generator step-up~~ transformer impedance and the actual Reactive Power

achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on ~~generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU~~generator step-up~~ transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The voltage drop across the GSU~~generator step-up~~ transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer and accounts for the turns ratio and impedance.~~ of the generator step-up transformer.~~ The actual generator bus voltage may be higher depending on the GSU~~generator step-up~~ transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU~~generator step-up~~ transformers. Table 1, Option 10 is provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU~~generator step-up~~ transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU~~generator step-up~~ transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU~~generator step-up~~ transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU~~generator step-up~~ transformer. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU~~generator step-up~~ transformer's turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~generator step-up transformers.~~ Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

Table 1, Option 12 is provided for assessing loadability for GSU~~generator step-up~~ transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU~~generator step-up~~ transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU~~generator step-up~~ transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU~~generator step-up~~ transformer times the GSU~~turns ratio of the generator step-up~~ transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU~~generator step-up~~ transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT~~unit auxiliary transformer(s) ("UAT")~~ that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying applied at the high-side of~~protecting~~ UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied at the high-side of ~~to~~ the UAT that remove the transformer from service resulting in an immediate (e.g.,~~act to trip the generator directly or~~ via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~Phase~~ time overcurrent relaying applied to the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result~~that results~~ in a generator runback. ~~are not a part of this standard.~~ Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the F~~f~~igures 6 and 7 below for example configurations:

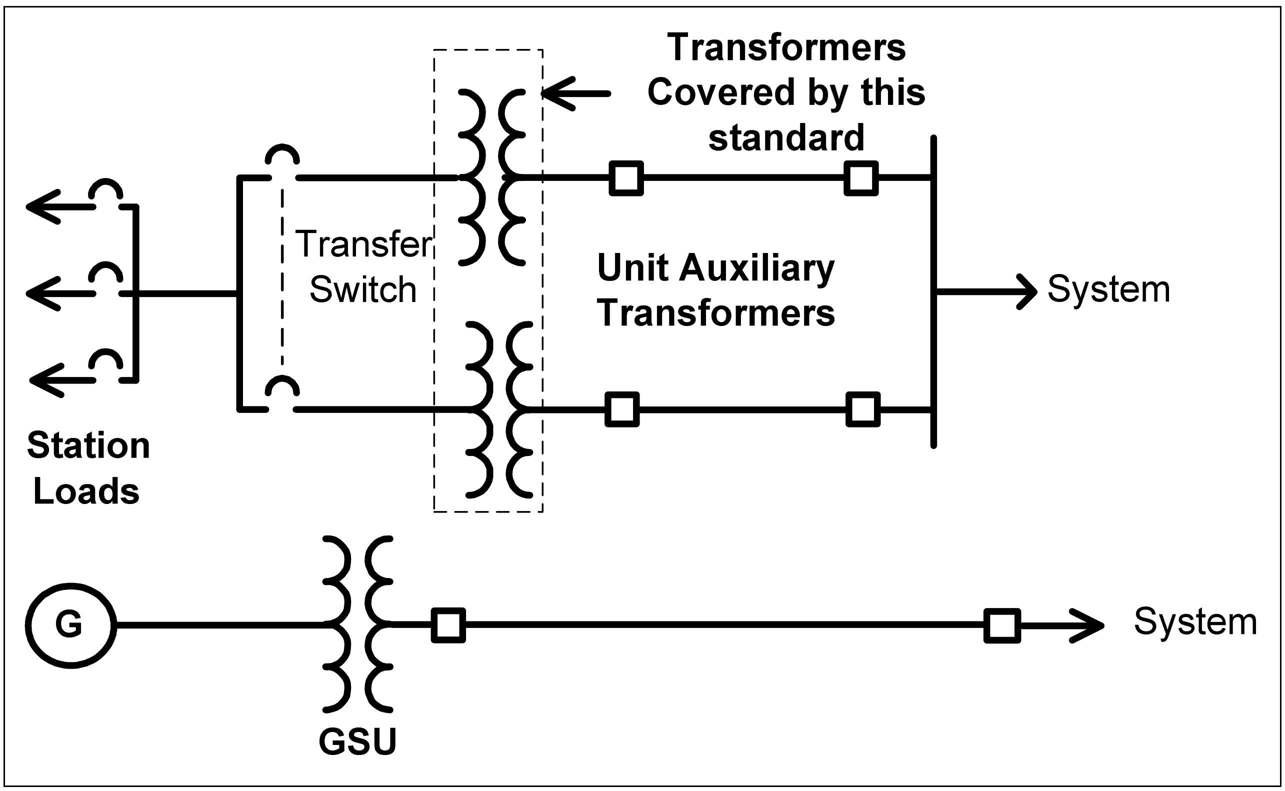


Figure-6 – Auxiliary Power System (independent from generator).

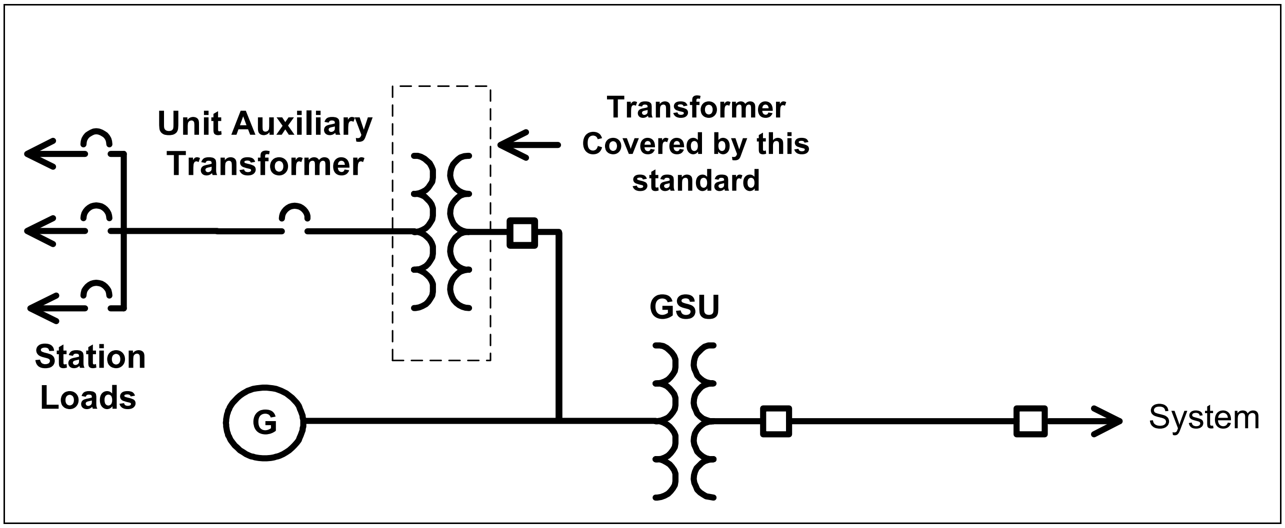


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on~~calculate~~ the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT~~or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary~~.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner.~~, or other entity as specified by the Regional Reliability Organization.~~ This allows for a reduced setting pickup compared to Option 13a and the ~~but does allow for an~~ entity's relay setting philosophy.~~ Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location.~~ This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent)~~%)~~ and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator Interconnection Facilities~~ (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ are challenged by loading conditions similar to relays applied on generators and GSU~~generator step-up~~ transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU~~generator step-up~~ transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU~~generator step-up~~ transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator Interconnection Facilities~~ (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ are challenged by loading conditions similar to relays applied on generators and GSU~~generator step-up~~ transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU~~generator step-up~~ transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~, thus Option 16~~15~~ is used for these relays as well.

~~Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator interconnection Facilities phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the aggregate generation~~

~~MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.~~

~~For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)~~

~~Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 16 is used for these relay as well.~~

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU~~generator step-up~~ transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner~~ or other entity as specified by the Regional Reliability Organization~~, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator Interconnection Facilities~~ (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ are challenged by loading conditions similar to relays applied on generators and GSU~~generator step-up~~ transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator Interconnection Facilities~~ (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ are challenged by loading conditions similar to relays applied on generators and GSU~~generator step-up~~ transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~Generator Interconnection Facilities~~ (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ are challenged by loading conditions similar to relays applied on generators and GSU~~generator step-up~~ transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generator interconnection Facilities~~ from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU~~generator step-up~~ transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU~~generator step-up~~ transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the

Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} \cancel{V_{gen\ nom}} = 22\ kV$
Real Power output in MW as reported to the ~~PC or~~ TP:	$P_{Synch\_reported} \cancel{P_{reported}} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU~~Generator step-up~~ transformer reactance~~impedance~~ (903 MVA base):	$X_{GSU} \cancel{Z_{gsu}} = 12.14\%$
GSU~~Generator step-up~~ transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU~~Generator step-up~~ transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT~~Potential transformer~~ ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary~~Auxiliary~~ transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT~~Auxiliary~~ low-side voltage:	$V_{UAT} \cancel{V_{uat}} = 13.8\ kV$
UAT CT ratio:~~Auxiliary current transformer:~~	$CT_{UAT} \cancel{CT_{uat}} = \frac{5000}{5}$
~~Current transformer High Voltage~~ CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive P~~p~~ower output of static reactive device:	$MVAR_{static} = 15\cancel{20}\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$

Example Calculations.	
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\cancel{120}\ MVA$
	$pf = 0.85$
Asynchronous CT~~current transformer~~ ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage~~current transformer High Voltage~~ CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times \cancel{GEN_{Synch\_namplate} \times} pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$Q = 1.50\cancel{5} \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} \cancel{P_{reported}} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58.7°\ MVA$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$Z_{pri} = 0.321\angle 58.7°\ \Omega$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\,\Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\,\Omega}{1.15} \cancel{\frac{8.035\angle 58.7°\Omega}{1.15}}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\,\Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\,\Omega}{\cos(85.0° - 58.7°)} \cancel{\frac{6.9873\Omega}{\cos(85.0° - 58.7°)}}$$

$$Z_{max} < \frac{6.9873\,\Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\,\Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system ~~relay~~. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (21) directional toward the Transmission system ~~relay~~.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \cancel{GEN_{Synch\_namplate}} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$Q = 1.5\cancel{05} \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):~~.~~

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}} \cancel{\frac{P_{reported}}{MVA_{base}}}$

$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$

$P_{pu} = 0.91\ p.u.$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$

$Q_{pu} = 1.5\ p.u.$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$

$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$

$X_{pu} = 0.1032\ p.u.$

Using~~Use~~ the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$

$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = 6.7°$$

Eq. (15)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

Eq. (16)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

Example Calculations: Options 1b and 7b

$$V_{bus} = 0.9998\,p.u.\times 345\,kV \times \left(\frac{22\,kV}{346.5\,kV}\right)$$

$$V_{bus} = 21.90\,kV$$

Apparent power (S):

Eq. (19) $S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$

$$S = 700.0\,MW + j1151.3\,Mvar$$

$$S = 1347.4\angle 58.7°\ \underline{MVA}$$

Primary i~~I~~mpedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.90\,kV)^2}{1347.4\angle -58.7°\,MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\,\Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.356\angle 58.7°\,\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\,\Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\,\Omega$$

To satisfy the 115% margin in ~~the requirement in~~ Options 1b and 7b:

Eq. (22) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\,\Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Example Calculations: Options 1b and 7b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0^{\circ} - 58.7^{\circ})} \cancel{\frac{7.74\Omega}{\cos(85.0^{\circ} - 58.7^{\circ})}}$$

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0^{\circ}\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although~~in this example~~ the ~~maximum~~ excitation limiter reduces~~is not modeled. The derivation would be~~ the field,~~same if~~ the duration of~~limiter were modeled, using~~ the ~~maximum~~ Reactive Power output achieved for this condition is sufficient to operate a phase distance relay~~attained and corresponding voltage during field-forcing~~.

In this simulation the following values are derived:

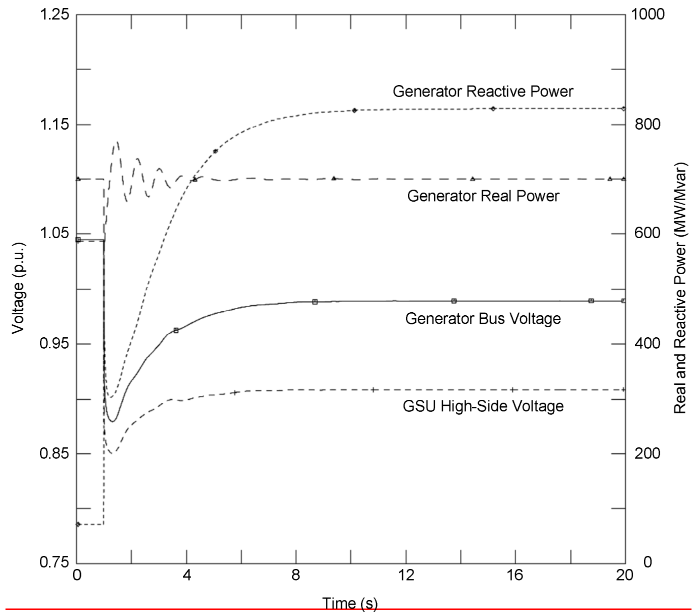
~~Q = 829.3 Mvar~~

~~V_{bus} = 0.990 = 21.78 kV~~

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,~~

~~$P_{reported}$ = 700.0 MW~~

Example Calculations: Options 1c and 7c

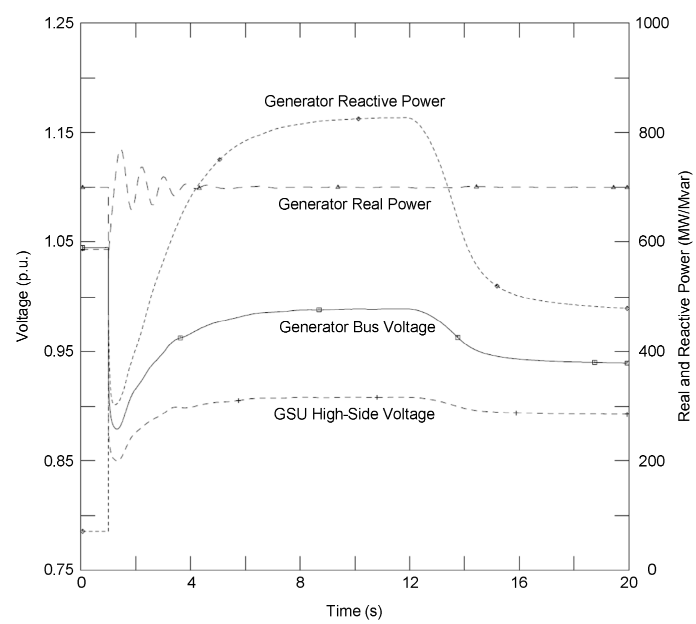


$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$$

Example Calculations: Options 1c and 7c

$$S = 700.0\ MW + j827.4\cancel{j829.3}\ Mvar$$

$$S = 1083.8\cancel{1085.2}\angle 49.8°\ MVA$$

Primary i~~I~~mpedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}\cancel{\frac{(21.78\ kV)^2}{1085.2\angle -49.8°\ MVA}}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}\cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{sec\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\ limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{sec\ limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0˚ - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

Example Calculations: Options 1c and 7c

$$Z_{max} < 11.63\angle 85.0°\,\Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $P = GEN_{Synch\_nameplate} \times \cancel{GEN_{synch\_namplate} \times} pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$$Q = 1.50\cancel{5} \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

Example Calculations: Option 2a

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}} \cancel{\frac{37383\ A}{\frac{25000}{5}}}$$

$$I_{sec} = 7.477\ A\cancel{A}$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A\cancel{A} \times 1.15$$

$$I_{\sec limit} > 8.598\ A\cancel{A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times \cancel{GEN_{Synch\_namplate} \times} pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50\cancel{5} \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).~~.~~

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}} \cancel{\frac{P_{reported}}{MVA_{base}}}$$

Example Calculations: Option 2b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}\cancel{\frac{1151.3\ Mvar}{767.6 MVA}}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}\cancel{\left(\frac{MVA_{base}}{MVA_{GSU}}\right)}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using~~Use~~ the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA\cancel{MVA}$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}} \cancel{\frac{35553\ A}{\frac{25000}{5}}}$$

$$I_{sec} = 7.111\ A\cancel{A}$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A\cancel{A} \times 1.15$$

$$I_{\sec limit} > 8.178\ A\cancel{A}$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent~~impedance~~ element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current.~~lowest apparent impedance.~~ The corresponding generator bus voltage is also used in the calculation. Note that although~~in this example~~ the ~~maximum~~ excitation limiter reduces~~is not modeled. The derivation would be~~ the field,~~same if~~ the duration of~~limiter were modeled, using~~ the ~~maximum~~ Reactive Power output achieved for this condition is sufficient to operate a~~attained and corresponding~~ voltage-restrained phase overcurrent relay~~during field-forcing~~.

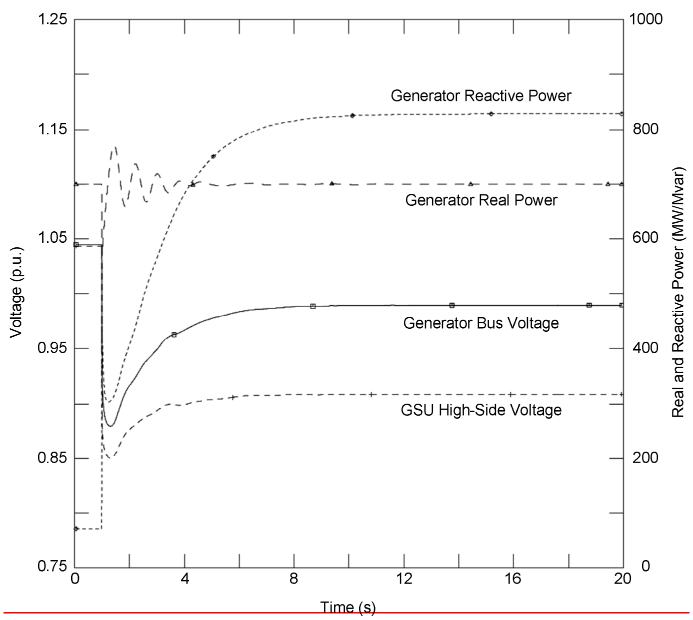
In this simulation the following values are derived:

~~Q = 829.3 Mvar~~

~~V_{bus} = 0.990 = 21.78 kV~~

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,~~

~~$P_{reported}$ = 700.0 MW~~



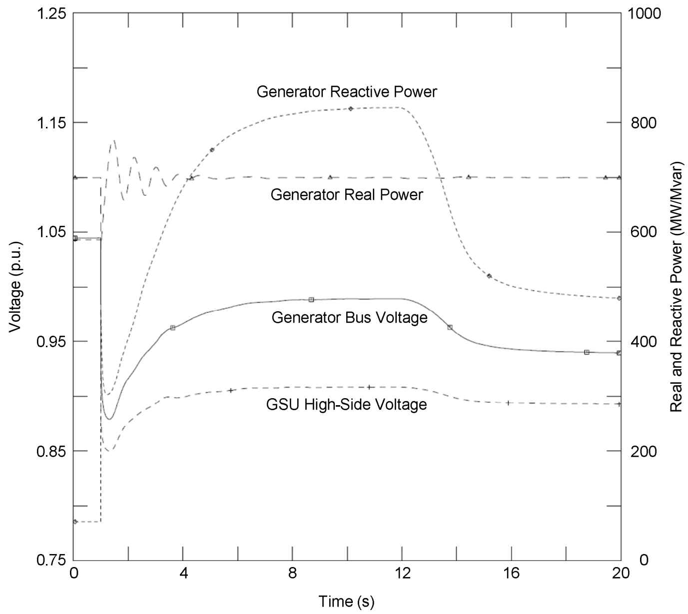
$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} \cancel{P_{reported}} + jQ$

$S = 700.0\ MW + j827.4 \cancel{j829.3}\ Mvar$

$S = 1083.8 \cancel{1085.2} \angle 49.8°\ MVA$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV} \cancel{\frac{1085.2\ MVA}{1.73 \times 21.78\ kV}}$$

$$I_{pri} = 2879\cancel{8}0\cancel{1}\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}} \cancel{\frac{28801\ A}{\frac{25000}{5}}}$$

$$I_{sec} = 5.758\ A\ \cancel{760\ A}$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A\ \cancel{760\ A} \times 1.15$$

$$I_{\sec limit} > 6.622\ A\ \cancel{624\ A}$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

Example Calculations: Options 3 and 6

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option~~s~~ 4 ~~and 10~~

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system ~~relay. In this application it was assumed 20 Mvar of static compensation was added~~.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych\_nameplate} \cancel{GEN_{Asych\_namplate}} \times pf$$

$$P = 40\cancel{120}\ MVA \times 0.85$$

$$P = 34\cancel{102}.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \cancel{MVAR_{static} + GEN_{Async\_namplate}} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))\ \cancel{Q = 20\ Mvar + 63.2\ Mvar}$$

$$Q = 21.1\cancel{83.2}\ Mvar$$

Option~~s~~ 4 ~~and 10~~, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34\cancel{102}.0\ MW + j21.1\cancel{j83.2}\ Mvar$$

$$S = 40.0\angle 31.8\cancel{131.6\angle 39.2}°\ MVA$$

Example Calculations: Option~~s~~ 4 ~~and 10~~

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}\cancel{\frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}}$$

$$Z_{pri} = 11.99\ \angle 31.8\cancel{3.644\ \angle 39.2}°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \cancel{3.644\ \angle 39.2°}\Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}\cancel{\frac{\frac{5000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 11.99\ \angle 31.8\cancel{3.644\ \angle 39.2}°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8\cancel{18.22\ \angle 39.2}°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}\cancel{\frac{18.22\angle 39.2°\ \Omega}{1.30}}$$

$$Z_{\sec limit} = 46.12\angle 31.8\cancel{14.02\angle 39.2}°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}\cancel{Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}\cancel{\frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}\cancel{\frac{14.02\ \Omega}{0.6972}}$$

$$Z_{max} < 77.0\cancel{20.109}\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for three asynchronous generators applying a phase time overcurrent (51V-R) – voltage-restrained relay. In this application it was assumed 20 Mvar~~20Mvar~~ of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \cancel{GEN_{Asynch\_namplate}} \times pf$$

$$P = 3 \times 40\cancel{120}\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \cancel{GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q = 15\cancel{20}\ Mvar + 5\cancel{63.2}\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Example Calculations: Option 5

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}} \cancel{\frac{3473\angle -39.2°\ A}{\frac{5000}{5}}}$$

$$I_{sec} = 3.473\angle -39.2°\ A\cancel{A}$$

To satisfy the 130% margin in Option 5:

Eq. (70) $$I_{sec\,limit} > I_{sec} \times 130\%$$

$$I_{sec\,limit} > 3.473\angle -39.2°\ A\cancel{A} \times 1.30$$

$$I_{sec\,limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system ~~relay~~. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation **(Option 7a)**

Real Power output (P_{sync}):

Eq. (71) $$P_{Synch}\cancel{P_{sync}} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch}\cancel{P_{sync}} = 903\ MVA \times 0.85$$

$$P_{Synch}\cancel{P_{sync}} = 767.6\ MW$$

$$\cancel{P_{sync-reported} = 700\ MW}$$

Reactive Power o~~O~~utput (Q_{synch}):~~(Q_{sync})~~

Eq. (72) $$Q_{Synch}\cancel{Q_{sync}} = 150\% \times P_{Synch}\cancel{P_{synch}}$$

$$Q_{Synch} = 1.50 \times \cancel{Q_{sync} = 150\% \times} 767.6\ MW$$

$$Q_{Synch}\cancel{Q_{sync}} = 1151.3\ MW$$

Apparent power (S_{Synch}):~~Power (S_{sync})~~

Eq. (73) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}\cancel{S_{sync} = P_{sync-reported} + jQ_{synch}}$$

Example Calculations: Options 7a and 10

$$S_{Synch} = 700.0\ MW \cancel{S_{sync} = 700MW} + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}): ~~P_{async}):~~

Eq. (74) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf \cancel{P_{async} = GEN_{Asynch\_namplate} \times pf}$$

$$P_{Asynch} = 3 \times 40 \cancel{P_{async} = 120}\ MVA \times 0.85$$

$$P_{Asynch} \cancel{P_{async}} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}): ~~Q_{async}):~~

Eq. (75) $$Q_{Asynch} \cancel{Q_{async}} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \cancel{GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q_{Asynch} = 15 \cancel{Q_{async} = 20}\ Mvar + 5\cancel{63.2}\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} \cancel{Q_{async}} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (76) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage~~calls~~ for the generator bus voltage and Option 10 specifies~~a~~ 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due~~, however due~~ to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:~~):~~

Eq. (77~~76~~) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (78~~77~~) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right) \cancel{S = 1.15 \times \left(P_{sync-reported} + jQ_{sync}\right) + 1.30 \times \left(P_{async} + jQ_{async}\right)}$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) \cancel{(700\ MW + j1151.3\ Mvar)} + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 7a and 10

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (79~~78~~) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (80~~79~~) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}} \cancel{\frac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 85~~77~~ to satisfy the margin requirements in Options 7a and 10:

Eq. (81~~80~~) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00} \cancel{\frac{6.32\ \angle 56.8°\ \Omega}{1.00}}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, ~~and~~ then the maximum allowable impedance reach is:

Eq. (82~~81~~) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})} \cancel{Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)} \cancel{\frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881} \cancel{\frac{6.32\ \Omega}{0.881}}$$

Example Calculations: Options 7a and 10

$Z_{max} < 7.17\angle 85.0° \,\Omega$

Example Calculations: Options 8a~~, 9a, 11,~~ and 9a~~12~~

Options 8a and 9a~~This~~ represents the simplest calculation for ~~a mixture of asynchronous and~~ synchronous generators applying a phase time overcurrent (51) relay.~~. In this application it was assumed 20 Mvar of static compensation was added.~~ The following uses~~CTs are located on~~ the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate~~low-side of~~ the option:~~GSU.~~

~~Synchronous Generation~~

Real Power output (P):~~P_{sync}):~~

Eq. (83~~82~~) $P = GEN_{Synch\_nameplate} \times pf$ ~~$P_{sync} = GEN_{Synch\_nameplate} \times pf$~~

$P =$ ~~$P_{sync} =$~~ $903\ MVA \times 0.85$

$P =$ ~~$P_{sync} =$~~ $767.6\ MW$

~~$P_{sync-reported} = 700\ MW$~~

Reactive Power output (Q):~~Output (Q_{sync})~~

Eq. (84~~83~~) $Q =$ ~~$Q_{sync} =$~~ $150\% \times P$~~P_{synch}~~

$Q = 1.50 \times$ ~~$Q_{sync} = 150\% \times$~~ $767.6\ MW$

$Q =$ ~~$Q_{sync} =$~~ $1151.3\ Mvar$

~~Apparent Power (S_{sync})~~

~~Eq. (84) $S_{sync} = P_{sync-reported} + jQ_{synch}$~~

~~$S_{sync} = 700\ MW + j1151.3\ Mvar$~~

~~$S_{sync} = 1347.4\ \angle 58.7°\ MVA$~~

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~for~~ generator bus voltage (V_{gen}):

Eq. (85) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a~~, 9a, 11,~~ and ~~9a~~12

Apparent power (S):

Eq. (86) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (87) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \dfrac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (88) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \dfrac{37383\ A}{\frac{25000}{5}}$

$I_{sec} = 7.477\ A$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (89) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 7.477\ A \times 1.15$

$I_{\sec limit} > 8.598\ A$

~~Example Calculations: Options 8b and 9b~~

Options 8b and 9b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (90) $P = GEN_{Synch\_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

Example Calculations: Options 8b and 9b

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (91) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (92) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (93) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (94) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (95) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

Example Calculations: Options 8b and 9b

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (96)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (97)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (98)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (99)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 8b and 9b

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (100) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (101) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (102) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (103) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (104) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (105) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (106) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (107) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):~~Current ($I_{pri-sync}$):~~

Eq. (108~~86~~) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}} \cancel{\frac{1.15 \times S^{*}_{sync}}{\sqrt{3} \times V_{gen}}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A\cancel{A}$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous **Generation (Options 11 and 12)**

Real Power output (P$_{Asynch}$): ~~P_{async}):~~

Eq. (109~~87~~) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$ ~~$P_{async} = GEN_{Asynch\_namplate} \times pf$~~

$P_{Asynch} = 3 \times 40$ ~~$P_{async} = 120$~~ $MVA \times 0.85$

P_{Asynch} ~~P_{async}~~ $= 102.0\ MW$

Reactive Power output (Q$_{Asynch}$): ~~Q_{async}):~~

Eq. (110~~88~~) Q_{Asynch} ~~Q_{async}~~ $= MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate}$ ~~$GEN_{Asynch\_namplate}$~~ $\times \sin(\cos^{-1}(pf))$

$Q_{Asynch} = 15$ ~~$Q_{async} = 20$~~ $Mvar + 56$~~3.2~~ $Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

Q_{Asynch} ~~Q_{async}~~ $= 83.2\ Mvar$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V$_{gen}$), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (111~~89~~) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$V_{gen} = 20.81\ kV$

Apparent power (S$_{Asynch}$): ~~S_{async}):~~

Eq. (112~~90~~) $S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$ ~~$S_{async} = 1.30 \times (P_{async} + jQ_{async})$~~

S_{Asynch} ~~S_{async}~~ $= 1.30 \times (102.0\ MW + j83.2\ Mvar)$

S_{Asynch} ~~S_{async}~~ $= 171.1\ \angle 39.2°\ MVA$

Primary current (I$_{pri\text{-}async}$): ~~Current ($I_{pri-async}$):~~

Eq. (113~~91~~) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2°\ MVA}{1.73 \times 20.81\ kV} \cancel{\frac{(171.1 \angle -39.2°\ MVA)}{1.73 \times 20.81\ kV}}$$

$I_{pri-async} = 4755 \angle -39.2°\ A$~~A~~

Example Calculations: Options 8a, 9a, 11, and 12

Secondary current (I_{sec}):

Eq. (114~~92~~) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\angle -58.7°\,A}{\frac{25000}{5}}\cancel{\frac{43061\angle -58.7°\,A}{\frac{25000}{5}}} + \frac{4755\angle -39.2°\,A}{\frac{25000}{5}}\cancel{\frac{4755\angle -39.2°\,A}{\frac{25000}{5}}}$$

$$I_{sec} = 9.514\angle -56.8°\,A\cancel{A}$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 94~~86~~ and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 98:~~90.~~

Eq. (115~~93~~) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\,A\cancel{A} \times 1.00$$

$$I_{\sec limit} > 9.514\angle -56.8°\,A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current.~~lowest apparent impedance.~~ The corresponding generator bus voltage is also used in the calculation. Note that although~~in this example~~ the ~~maximum~~ excitation limiter reduces~~is not modeled. The derivation would be~~ the field,~~same if~~ the duration of the ~~limiter were modeled, using the maximum~~ Reactive Power output achieved for~~attained and corresponding voltage during field-forcing.~~

~~In~~ this condition~~simulation the following values are derived:~~

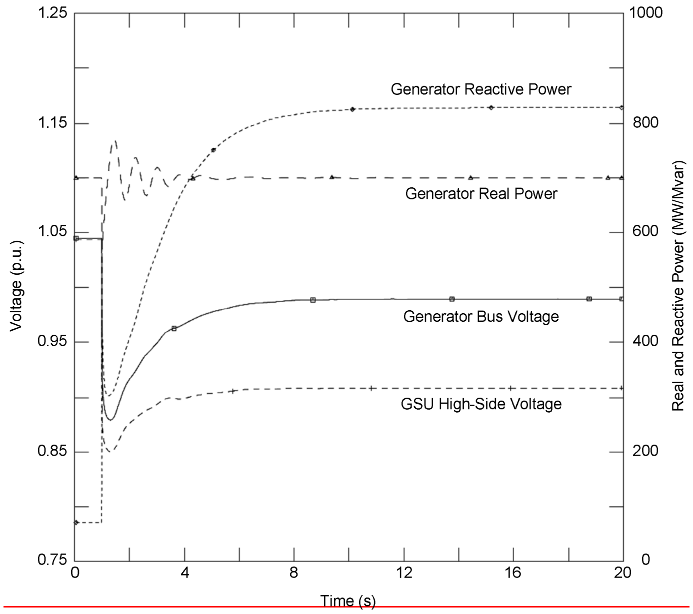
~~Q = 829.3 Mvar~~

~~V_{bus} = 0.990 = 21.78 kV~~

~~The other value required~~ is sufficient~~the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported~~ to operate a phase overcurrent relay.~~the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,~~

~~$P_{reported}$ = 700.0 MW~~

Example Calculations: Options 8c and 9c

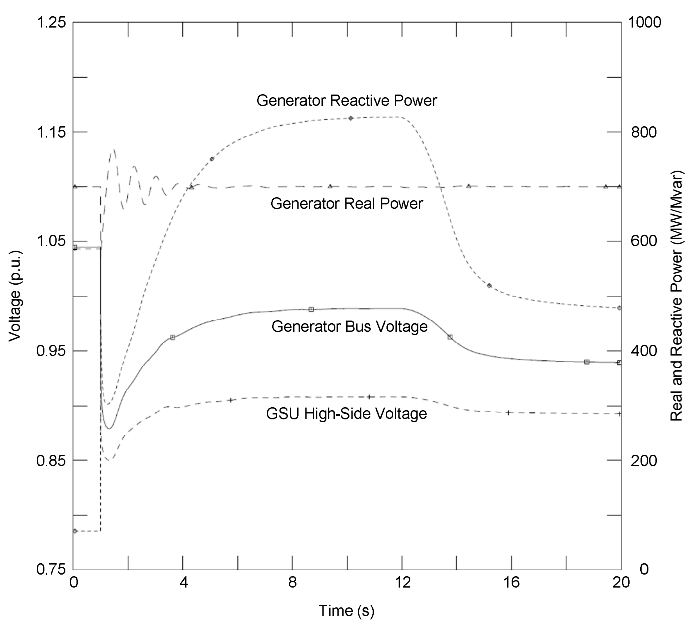


$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Example Calculations: Options 8c and 9c

Apparent power (S):

Eq. (116~~94~~) $S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$

$S = 700.0\ MW + j827.4\cancel{j829.3}\ Mvar$

$S = 1083.8\cancel{1085.2}\angle 49.8°$

Primary current (I_{pri}):

Eq. (117~~95~~) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}\cancel{\frac{1085.2\ MVA}{1.73 \times 21.78\ kV}}$

$I_{pri} = 2879\cancel{8}0\cancel{1}\ A$

Secondary current (I_{sec}):

Eq. (118~~96~~) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}\cancel{\frac{28801\ A}{\frac{25000}{5}}}$

$I_{sec} = 5.758\ A\cancel{760\ A}$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (119~~97~~) $I_{sec\,limit} > I_{sec} \times 115\%$

$I_{sec\,limit} > 5.758\ A\cancel{760\ A} \times 1.15$

$I_{sec\,limit} > 6.622\ A\cancel{624\ A}$

Example Calculations: Option10~~Options 11 and 12~~

This~~Option 11~~ represents the calculation for three asynchronous generators (including inverter-based installations)~~a GSU transformer~~ applying a phase distance~~time overcurrent (51)~~ relay (21) ~~–connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67)~~ directional toward the Transmission system~~ relay~~. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (120~~98~~) $P = 3 \times GEN_{Asych\_nameplate}\cancel{GEN_{Asynch\_namplate}} \times pf$

Example Calculations: Option10~~Options 11 and 12~~

$$P = 3 \times 40\cancel{120}\ MVA \ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (121~~99~~)

$$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \cancel{GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q = 15\cancel{20}\ Mvar + 5\cancel{63.2}\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (122) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (123) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2^\circ\ MVA$$

Primary impedance (Z_{pri}):

Eq. (124) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2^\circ\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2^\circ\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (125) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2^\circ\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

Example Calculations: Option10~~Options 11 and 12~~

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (126) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (127) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < \ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (128) $$P = \ 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (129) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

~~Example Calculations: Options 11 and 12~~

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (130~~100~~) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (131~~101~~) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (132~~102~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (133~~103~~) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (134~~104~~) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

~~Example Calculations: Options 11 and 12~~

$$I_{\sec limit} > 4.515\angle -39.2°\,A$$

Example Calculations: Options 13a and 13b

Option 13a forof the ~~unit auxiliary transformer (~~UAT~~)~~ assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.~~, or other entity as specified by the Regional Reliability Organization.~~

Primary current (I_{pri}):

Eq. (135~~105~~)
$$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}} \cancel{\frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}}$$

$$I_{pri} = \frac{60\,MVA}{1.73 \times 13.8\,kV}$$

$$I_{pri} = 2510.2\,A$$

Secondary current (I_{sec}):

Eq. (136~~106~~)
$$I_{sec} = \frac{I_{pri}}{CT_{UAT}} \cancel{\frac{I_{pri}}{CT_{uat}}}$$

$$I_{sec} = \frac{2510.2\,A}{\frac{5000}{5}} \cancel{\frac{2510.2\,A}{\frac{5000}{5}}}$$

$$I_{sec} = 2.51\,\text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (137~~107~~)
$$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\,A\cancel{A} \times 1.50$$

$$I_{\sec limit} > 3.77\,A\cancel{A}$$

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is~~interconnection Facility~~ applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (138~~108~~) $$P = GEN_{Synch\_nameplate} \cancel{GEN_{Synch\_namplate}} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (139~~109~~) $$Q = 120\% \times P$$

$$Q = 1.20\cancel{2} \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (140~~110~~) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (141~~111~~) $$S = P_{Synch\_reported} \cancel{P_{reported}} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (142~~112~~) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

Example Calculations: Option 14a

$$Z_{pri} = 74.335\angle 52.77°\,\Omega$$

Secondary impedance (Z_{sec}):

Eq. (143~~113~~) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}} \cancel{\frac{CT_{hv}}{PT_{hv}}}$$

$$Z_{sec} = 74.335\angle 52.77°\,\Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\,\Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (144~~114~~) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\,\Omega}{1.15} \cancel{\frac{14.867\angle 52.77°\ \Omega}{1.15}}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\,\Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (145~~115~~) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})} \cancel{Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$Z_{max} < \frac{12.928\,\Omega}{\cos(85.0° - 52.77°)} \cancel{\frac{12.928\Omega}{\cos(85.0° - 52.77°)}}$$

$$Z_{max} < \frac{12.928\,\Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\,\Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is~~interconnection Facility~~ applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although~~in this example~~ the ~~maximum~~ excitation limiter reduces~~is not modeled. The derivation would be~~ the field,~~same if~~ the duration of~~limiter were modeled, using~~ the ~~maximum~~ Reactive Power output achieved for this condition is sufficient to operate a phase distance relay~~attained and corresponding voltage during field-forcing~~.

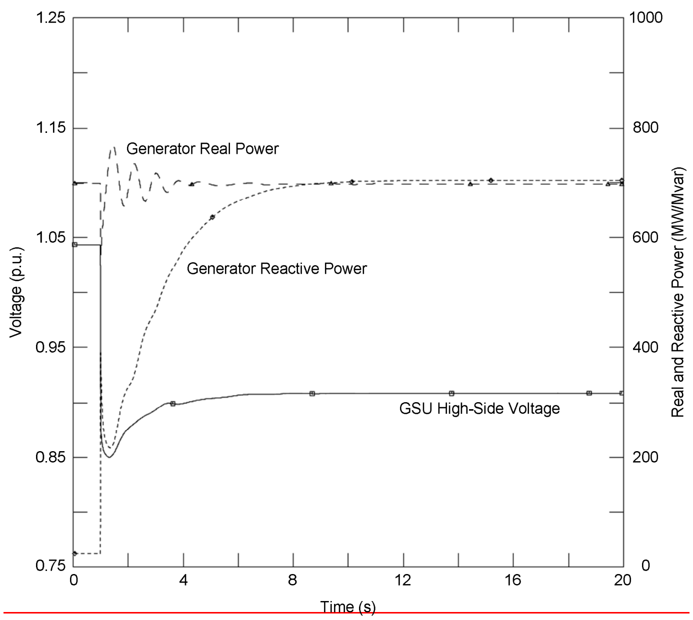
In this simulation the following values are derived:

~~Q = 704.4 Mvar~~

~~V_{bus} = 0.908 = 313.3 kV~~

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,~~

~~$P_{reported}$ = 700.0 MW~~



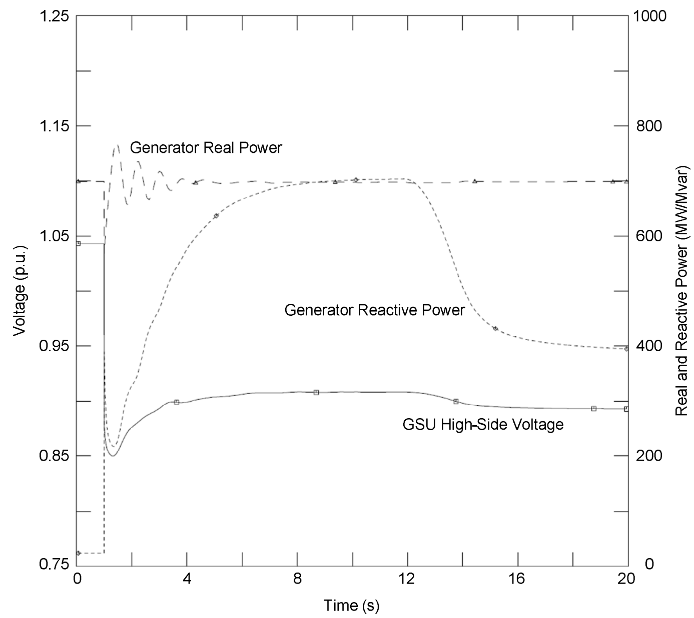
$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Option 14b



Apparent power (S):

Eq. (146~~116~~) $$S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$$

$$S = 700.0\ MW + j703.6\cancel{j704.4}\ Mvar$$

$$S = 992.5\cancel{993.1}\angle 45.1\cancel{2}^{\circ}\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1\cancel{2}^{\circ}$$

Primary impedance (Z_{pri}):

Eq. (147~~117~~) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1^{\circ}\ MVA}\cancel{\frac{(313.3\ kV)^2}{993.1\angle -45.2^{\circ}\ MVA}}$$

$$Z_{pri} = 98.90\cancel{84}\angle 45.1\cancel{2}^{\circ}\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (148~~118~~) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}\cancel{\frac{CT_{hv}}{PT_{hv}}}$$

$$Z_{sec} = 98.90\cancel{84}\angle 45.1\cancel{2}^{\circ}\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\cancel{84}\angle 45.1\cancel{2}^{\circ}\ \Omega \times 0.2$$

Example Calculations: Option 14b

$$Z_{sec} = 19.78\cancel{77}\angle 45.1\cancel{2}°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (149~~119~~) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15} \cancel{\frac{19.77\angle 45.2°\ \Omega}{1.15}}$$

$$Z_{\sec limit} = 17.20\cancel{19}\angle 45.1\cancel{2}°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, ~~and~~ then the maximum allowable impedance reach is:

Eq. (150~~120~~) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})} \cancel{Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)} \cancel{\frac{17.19\ \Omega}{\cos(85.0° - 45.2°)}}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767} \cancel{\frac{17.19\ \Omega}{0.768}}$$

$$Z_{max} < 22.42\cancel{38}\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15a represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~.~~

Real Power output (P):

Eq. (151~~121~~) $$P = GEN_{Synch\_nameplate} \cancel{GEN_{Synch\_namplate}} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (152~~122~~) $$Q = 120\% \times P$$

$$Q = 1.20\cancel{2} \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (153~~123~~) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (154~~124~~) $$S = P_{Synch\_reported} \cancel{P_{reported}} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (155~~125~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\,MVA}{1.73 \times 293.25\,kV}\cancel{\frac{1157\angle -52.8°\,MVA}{1.73 \times 293.25\,kV}}$$

$$I_{pri} = 2280.6\angle -52.8°\,A$$

Secondary current (I_{sec}):

Eq. (156~~126~~) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}\cancel{\frac{I_{pri}}{CT_{hv}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}\cancel{\frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}}$$

$$I_{sec} = 5.701\angle -52.8°\,A\cancel{A}$$

To satisfy the 115% margin in Options 15a and 15b:

Eq. (157~~127~~) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\,A\cancel{A} \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\,A\cancel{A}$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15b represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.~~.~~

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although~~in this example~~ the ~~maximum~~ excitation limiter reduces~~is not modeled. The derivation would be~~ the field,~~same if~~ the duration of~~limiter were modeled, using~~ the ~~maximum~~ Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay~~attained and corresponding voltage during field-forcing~~.

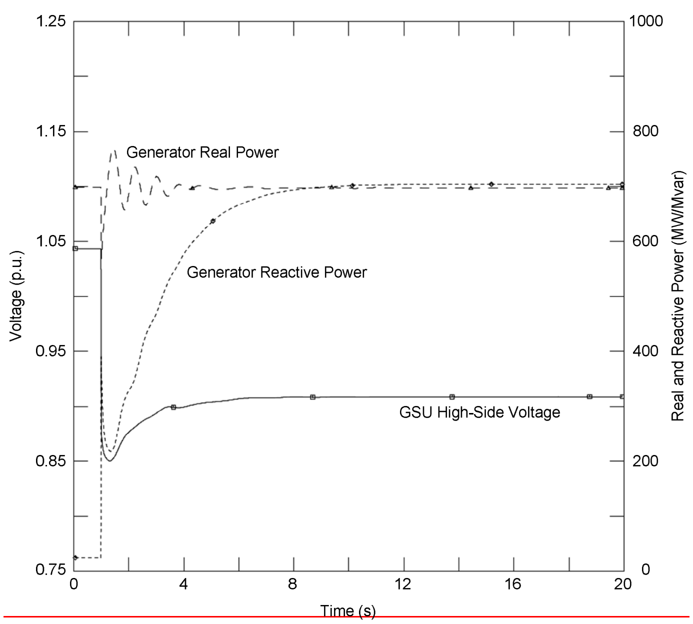
In this simulation the following values are derived:

~~$Q = 704.4$ Mvar~~

~~$V_{bus} = 0.908 = 313.3$ kV~~

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization. In this case,~~

~~$P_{reported} = 700.0$ MW~~



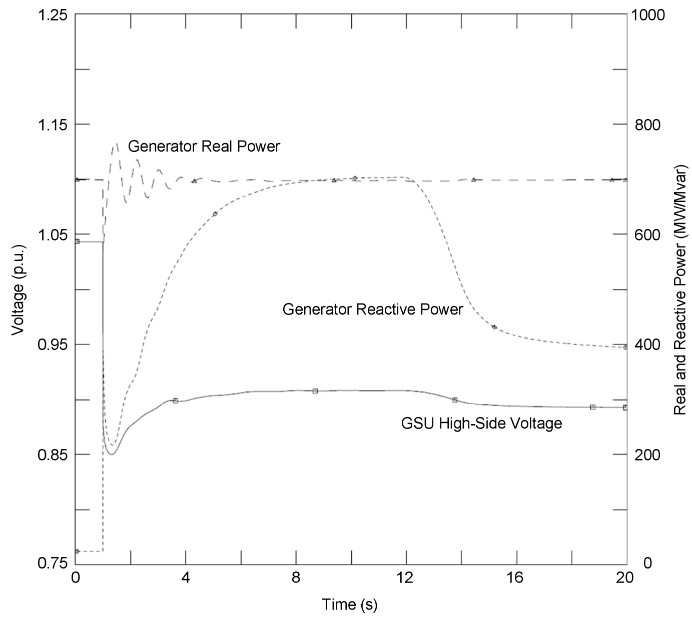
$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (158~~128~~) $$S = P_{Synch\_reported}\cancel{P_{reported}} + jQ$$

$$S = 700.0\ MW + j703.6\cancel{j704.4}\ Mvar$$

$$S = 992.5\cancel{993.1}\angle 45.1\cancel{2}°\ MVA$$

Primary current (I_{pri}):

Eq. (159~~129~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}\cancel{\frac{993.1\angle -45.2°\ MVA}{1.73 \times 313.3\ kV}}$$

$$I_{pri} = 1831\cancel{2}.2\angle -45.1\cancel{2}°\ A$$

Secondary current (I_{sec}):

Eq. (160~~130~~) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}} \cancel{\frac{1832.2\angle -45.2°\,A}{\frac{2000}{5}}}$$

$$I_{sec} = 4.578\cancel{580}\angle -45.1°\,A\cancel{2°\,A}$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (161~~131~~) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 4.578\cancel{580}\angle -45.1°\,A \times \cancel{2° \times} 1.15$$

$$I_{\sec limit} > 5.265\cancel{267}\angle -45.1°\,A\cancel{2°\,A}$$

Example Calculations: Option 17

Option 17 represents the calculation for three~~an~~ asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is~~interconnection facility~~ applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (162~~132~~) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf \cancel{P_{async} = GEN_{Asynch\_namplate} \times pf}$$

$$P_{Asynch} = 3 \times 40 \cancel{P_{async} = 120}\,MVA \times 0.85$$

$$P_{Asynch}\cancel{P_{async}} = 102.0\,MW$$

Reactive Power output (Q):

Eq. (163~~133~~) $$Q_{Asynch}\cancel{Q_{async}} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)\cancel{GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q_{Asynch} = 15\cancel{Q_{async} = 20}\,Mvar + 56\cancel{3.2}\,Mvar + (3 \times 40\,MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch}\cancel{Q_{async}} = 83.2\,Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0~~00~~ per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (164~~134~~) $$V_{bus} = 1.0\cancel{00}\,p.u. \times V_{nom}$$

Example Calculations: Option 17

$$V_{gen} = 1.\cancel{000} \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (165~~135~~) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (166~~136~~) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (167~~137~~) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (168~~138~~) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30} \cancel{\frac{27.13\angle 39.2°\ \Omega}{1.30}}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Example Calculations: Option 17

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (169~~139~~)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for three~~a~~ generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is~~interconnection Facility~~ applying a phase time overcurrent (51) relay connected to three~~an~~ asynchronous generators. Similarly, Option 19 may also be applied here for the phase directional time overcurrent relays (67) directional toward the Transmission system ~~relays~~ for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~generation interconnection Facilities~~. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (170~~140~~)
$$P = 3 \times GEN_{Asych\_nameplate} \cancel{GEN_{Asych\_namplate}} \times pf$$

$$P = 3 \times 40\cancel{120}\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (171~~141~~)
$$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \cancel{GEN_{Asych\_namplate} \times \sin(\cos^{-1}(pf))}$$

$$Q = 15\cancel{20}\ Mvar + 5\cancel{63.2}\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 18 and 19

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (172~~142~~) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (173~~143~~) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (174~~144~~) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (175~~145~~) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}} \cancel{\frac{220.5\angle -39.2°\ A}{\frac{300}{5}}}$$

$$I_{sec} = 3.675\angle -39.2°\ A\cancel{A}$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (176~~146~~) $$I_{sec\,limit} > I_{sec} \times 130\%$$

$$I_{sec\,limit} > 3.675\angle -39.2°\ A\cancel{A} \times 1.30$$

$$I_{sec\,limit} > 4.778\angle -39.2°\ A\cancel{A}$$

End of calculations

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Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-1, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability~~: Generator~~.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF. ~~Draft PRC-023-3 Requirement R7 and R8 replace Criterion 6 and also have a VRF of High. Requirements R7 and R8 establish identical criteria as established within PRC-025-1 for generator interconnection Facilities and generator step-up (GSU) transformers.~~
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on "pass-fail" or a binary condition. The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

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Project 2010-13.2 Generator Relay Loadability

Consideration of Issues and Directives

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
NERC Ref: S-10724 Para 106 supported by Paragraphs 104, 105, and 108. **106.** We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability. Para 104, 105, and 108 **104.** We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC-023-1 to address	Order No. 733 (Para 104, 105, 106, and 108)	**Response to P106** The Reliability Standard PRC-025-1 is responsive to paragraph 106 by establishing a new standard that addresses generator unit relay loadability for load-responsive protective relays applicable to generating Facilities for the conditions (depressed voltages) observed during the August 2003 blackout in the northeastern portion of North America. **Response to P104** The Reliability Standard PRC-025-1 is responsive to paragraph 104 by establishing requirements for load-responsive protective relays on generator step-up (GSU) transformers and on unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating units or generating plants. These

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC-023-1. **105.** In light of the EROs statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a		transformers are variably referred to as station power, UATs, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning UATs. The standard is coordinated with the expected outcomes of PRC-023-2 in that it will assure that the applicable equipment will not be removed from service unnecessarily for the conditions observed during the August 2003 blackout in the northeastern portion of North America. **Response to P105** The Reliability Standard PRC-025-1 is responsive to paragraph 105 by developing a new standard to address generator relay loadability according to the filed schedule. This Phase II of relay loadability required an extension of time to complete, extending the deadline to September 30, 2013. A one year extension was granted on February 15, 2012, Docket No. RM08-13-001.

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA. **108.** Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.		**Response to P108** The Reliability Standard PRC-025-1 is responsive to paragraph 108 by establishing a requirement for each Generator Owner, Transmission Owner, and Distribution Provider to apply settings on its load-responsive protective relays for GSU transformers. For GSU transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to the Transmission Planner, and 150% of the unit's Reactive Power capability, in megavoltampere-reactive (Mvar) derived from the generator nameplate megavoltampere (MVA) rating at rated power factor. For GSU transformers connected to asynchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on 100 percent of the

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the aggregated generators at rated power factor. Asynchronous generator criteria also include inverter-based installations.

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-025-1

Successive Ballot and Non-Binding Poll for PRC-025-1 now open through July 19, 2013

Now Available

A successive ballot of **PRC-025-1** – Generator Relay Loadability and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now being conducted through **8 p.m. Eastern on Friday, July 19, 2013**.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results for **PRC-025-1** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

An initial ballot of **PRC-023-3** will be conducted on July 26, 2013.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-025-1

Successive Ballot and Non-Binding Poll Results for PRC-025-1

Now Available

A successive ballot of **PRC-025-1** – Generator Relay Loadability and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Friday, July 19, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the successive ballot.

Approval	Non-binding Poll Results
Quorum: 85.05%	Quorum: 82.51%
Approval: 72.43%	Supportive Opinions: 64.59%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Results	
Ballot Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Ballot July 2013_sc_2
Ballot Period:	7/10/2013 - 7/19/2013
Ballot Type:	Successive
Total # Votes:	313
Total Ballot Pool:	368
Quorum:	**85.05 % The Quorum has been reached**
Weighted Segment Vote:	72.43 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	98	1	49	0.7	21	0.3	12	16
2 - Segment 2.	10	0.6	6	0.6	0	0	3	1
3 - Segment 3.	81	1	43	0.614	27	0.386	4	7
4 - Segment 4.	28	1	15	0.682	7	0.318	1	5
5 - Segment 5.	80	1	29	0.492	30	0.508	10	11
6 - Segment 6.	54	1	25	0.61	16	0.39	2	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	4	0.4	0	0	0	3
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1
10 - Segment 10.	7	0.7	7	0.7	0	0	0	0
Totals	**368**	**6.9**	**180**	**4.998**	**101**	**1.902**	**32**	**55**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	

1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	

3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	

4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Michael Shultz	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	

5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson		
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Colorado Springs	Shannon Fair	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	

6	Portland General Electric Co.	Ty Bettis	Negative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Legal and Privacy

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-binding Poll

Project 2010-13.2 PRC-025-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-13.2 Relay Loadability PRC-025-1 Non-binding
Poll Period:	7/10/2013 - 7/19/2013
Total # Opinions:	283
Total Ballot Pool:	343
Summary Results:	82.51% of those who registered to participate provided an opinion or an abstention; 64.59% of Those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
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1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
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1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		

1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	

1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Bandera Electric Cooperative	Brian D Bartos		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	Consumers Energy	Richard Blumenstock		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery	Abstain	

5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Michael Shultz	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant	Michiko Sell	Affirmative	

	County, Washington			
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Colorado Springs	Shannon Fair	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		

6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3 and PRC-025-1

45-Day Formal Comment Period for PRC-023-3: June 20, 2013 – August 5, 2013

Ballot Pools Forming Now: June 20, 2013 - July 19, 2013
Upcoming Initial Ballot: July 26, 2013 - August 5, 2013

30-Day Formal Comment Period for PRC-025-1: June 20, 2013 – July 19, 2013

Upcoming Successive Ballot and Non-Binding Poll: July 10, 2013 – July 19, 2013

Now Available

A 45-day formal comment period for **PRC-023-3** – Transmission Relay Loadability is now being conducted through **8 p.m. Eastern on Monday, August 5, 2013**. A ballot pool is being formed and the ballot pool window is open through **8 a.m. Eastern on Friday, July 19, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

A 30-day formal comment period for **PRC-025-1** – Generator Relay Loadability is now being conducted through **8 p.m. Eastern on Friday, July 19, 2013**.

Background information for this project can be found on the project page.

Instructions for Joining Ballot Pools

A ballot pool is being formed for the standard **PRC-023-3**. Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of PRC-023-3. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is:

Initial Ballot: bp-2010-13.2_PRC-023_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Friday, July 19, 2013**.

Instructions for Commenting

To submit comments, please use this electronic form for **PRC-023-3** and this electronic form for **PRC-025-1**. If you experience any difficulties in using the electronic form, please contact Wendy Muller . An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An initial ballot of **PRC-023-3** and a successive ballot of **PRC-025-1** and non-binding poll **(for PRC-025-1 only)** of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for both standards will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (43 Responses)
Name (21 Responses)
Organization (21 Responses)
Group Name (43 Responses)
Lead Contact (43 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (9 Responses)
Comments (43 Responses)
Question 1 (38 Responses)
Question 1 Comments (43 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
We disagree with the Drafting Team's decision not to make the change suggested during an earlier posting (remove the following words from R1 "...while maintaining reliable fault protection.") This phrase should be replaced and therefore suggest R1 be revised to read Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while achieving its desired protection goals.
Group
Duke Energy
Colby Bellville
No
The relays identified in this standard are shown at the high side winding of the UAT, there are many examples at Duke Energy where these relays are omitted from the design at that location. Duke Energy is concerned as to why the time overcurrent relays at the low side main breaker are not being included in this standard. These relays are set similarly and if a low side main "load responsive" relay operated unnecessarily, the outcome is similar. The generating unit would trip offline or at best run back to a reduced load. (if possible and only if multiple buses exist with diverse loads). The purpose of the standard is to improve the BES by setting "load responsive" protective relays at a level to prevent unnecessary tripping of generators. If the UAT high side "load responsive" relay is included within this standard, then the low side main "load responsive" relay must also be included. The low side main "load responsive" relays are typically set with similar criteria as the high side "load responsive" relays. The misoperation of either relay will result in lost generation. To omit the low side main "load responsive" relay from the standard means the owner can continue to set this relay at levels that would violate the intent of the standard. Lastly, the SDT should be aware that the low side main "load

responsive" relay is excluded from the protection maintenance standard.
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
1) The wording in Table 1, Options 15, 16, 18, and 19 could be interpreted to imply that in addition to the supervisory phase overcurrent elements used in communication based schemes to prevent false operation during loss of communications, that any 51 or 67 element that is intentionally armed during loss of communications would also be subject to this loadability criterion. This concept was extensively debated in the development of PRC-023. However, in PRC-023 Attachment A, Section 2.1 it specifically excludes "those elements that are only enabled during a loss of communications except as noted on Section 1.6". Section 1.6 applies only to "phase overcurrent supervisory elements (i.e. phase fault detectors) associated with current-based, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." Therefore to be consistent with PRC-023, and to not draw into scope other elements that are intentionally armed only during loss of communications, the following bullet should be added to the list of Exclusions in Attachment 1 of PRC-025-1: "Elements that are only enabled during a loss of communications except phase supervisory elements (i.e. phase fault detectors) associated with current-based, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." 2) In the Guidelines and Technical Basis document Equations 33, 47, 51, 87, 101, 113, and 117 all use the formula I pri = S / 1.73 Vbus. However, Equations 68, 132, 155, 159, and 174 all use the formula I pri = S (conjugate) /1.73 Vbus. Also, in some of the examples the angle of the current is calculated as well, while in others only scalar quantities are used. To be technically correct, the equation for I primary is developed from the apparent power expression S = V I (conjugate). Solving for I results in I pri = S (conjugate) / 1.73 V (conjugate). But since the angle of Vbus is assumed to be zero degrees Vbus = Vbus (conjugate). Therefore the correct expression reduces to I pri = S (conjugate) / 1.73 Vbus. For consistency purposes, the same equation should be used in all examples.
Group
Tennessee Valley Authority
Brandy Spraker
Agree
North American Generator Forum (NAGF)
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor

Yes
Negative vote for PRC-025-1: A high VRF is unjustified since a single unit relay setting error will have minimal impact on BES, particularly for smaller units.
Individual
NICOLE BUCKMAN
Atlantic City Electric Company
Pepco Holdings Inc and Affiliates
DAVID THORNE
Agree
Pepco Holdings Inc and Affiliates
Individual
Mark Yerger
Potomac Electric Power Company
Pepco Holdings, Inc. & Affiliates
David Thorne
Agree
Pepco Holdings, Inc. & Affiliates
Individual
Thomas Foltz
American Electric Power
N/A
N/A
Yes
Individual
Michael Falvo
Independent Electricity System Operator
NPCC
Barbara Constantinescu
Yes
Individual
Michael Mayer
Delmarva Power & Light Company

Pepco Holdings Inc. & Affiliates
David Thorne
Agree
Pepco Holdings Inc.& Affiliates
Individual
Rick Terrill
Luminant Generation Company LLC
Luminant
Rick Terrill
No
The additional work provided by the standard drafting team has clarified the bright line between PRC-025 and 023. However, Luminant disagrees with the loadability criteria (aggregate generation) used in PRC-025 for multiple lines used for exporting generation (Figure 2 in the Guidelines and Technical Basis document).The loadability criteria is too conservative when compared to PRC-023 Requirement R1 transmission line criteria. Luminant recommends that the loadability criteria used in PRC-023 for transmission lines be part of PRC-025 for use in cases where multiple lines are used to export energy.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
na
na
No
1. We appreciate the time and effort of the SDT members to develop this important standard. 2. However, as presently written, this standard will apply to individual wind turbine generators and other small dispersed generators by virtue of the new BES definition. To apply the rigorous requirements of this standard to the vast numbers of wind generators (typically less than 2 MW each) will require huge resources for minimal reliability benefit . The industry’s resources need to be focused on higher priorities affecting overall system reliability. To avoid this problem, we request that the Applicability be revised to include only generators rated above 20 MVA; for stations with aggregate generation over 75 MVA, the requirements should apply only to the relaying from the high-voltage transmission interconnection through the main transformer (eg, 138-34.5 kv). 3. Since there is no evidence that improper relay settings on UAT’s or SAT’s which supply generator auxiliary loads has contributed to loss of generation during disturbances, it is highly recommended to remove these elements from the requirements. These are lower priority risks which do not rise to the level of systemic reliability concerns.

Individual
Nazra Gladu
Manitoba Hydro
Manitoba Hydro
Nazra Gladu
Yes
Although Manitoba Hydro is in general agreement with the revisions to the standard, we have the following comments (1) 3.2 - add the acronym [(BES)] following the words “Bulk Electric System” since this is the first instance of these words in the standard. (2) PRC-025-1, Attachment 1: Relay Settings, Introduction - for clarity, add a comma after the word “Facilities”. (3) PRC-025-1, Attachment 1: Relay Settings, Introduction - for clarity, re-write the sentence as follows: “shall use one of the following [19] Options listed in Table 1,”. (4) PRC-025-1, Attachment 1: Relay Settings - capitalize all instances of the word “element” found throughout the attachment. (5) PRC-025-1, Section 3.1.1 - only refers to Generator Owners, yet R1 also applies to Transmission Owners and Distribution Providers. This discrepancy should be rectified. (6) The revisions to Section 3.2.4 and Attachment 1 use the term “export” means the transmission of electricity from one jurisdiction to a foreign jurisdiction. It is not clear why such a term would be used. Unless this was the actual intention, the term “export” should be replaced with [transmit] or [deliver]. (7) Implementation Plan - the chart’s Applicability section for R1 does not describe applicable entities, but instead describes a requirement.
Individual
Tim Brown
Idaho Power Company
n/a
n/a
Yes
Group
Bonneville Power Administration
Jamison Dye
No
BPA supports the addition of TO’s and DP’s to PRC-025 and the transfer of applicability for “lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network” from PRC-023 to PRC-025. However, we are concerned that certain protective relays at the network terminal of these lines are not addressed in Table 1. We appreciate that certain relays at the network terminal, directional toward the generation (for example phase distance relays), are not challenged by the same loadability concerns as the

relays at the generation terminal directional toward the network; however, these relays at the network terminal are presently required to comply with PRC-023, and we are a little skeptical that they will no longer need to comply in some way with either PRC-023 or PRC-025. It appears that they will be covered by PRC-025, but there is no mention of any requirements for compliance in Table 1. If there are really no loadability requirements for these relays, please state that in Table 1. If there are loadability requirements, please state what those are in Table 1. We also have a minor comment on the standard. Since PRC-023 and PRC-025 are so closely related, it would be helpful it they used the same terminology. PRC-023 uses the term, “except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network”, while PRC-025 uses the term, “elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.” We would like to see the same term used in both standards.
Group
Dominion
Louis Slade
Agree
North American Generator Forum
No
While Dominion does not agree with the SDT’s decision not to make the change we suggested (to remove the following words from R1 “...while maintaining reliable fault protection.”) we appreciate that they responsed. However, we remain convinced that this phrase should be replaced and therefore suggest R1 be revised to read “Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. achieving its desired protection goals. • Section 3.2 – remove the entire section (3.2, 3.2.1, 3.2.2, 3.2.3, and 3.2.4), the revised Section 3.1.1 now will cover this section. The current approach would expand on the existing definition of BES and is not acceptable.
Individual
Texas Reliability Entity
Texas Reliability Entity
NA
NA
Yes
We are voting FOR this standard, subject to the following comment: (1) Most references to “Regional Reliability Organization” were correctly removed from this draft, but one occurrence remains on page 1 of Attachment 1, third paragraph. That reference to RRO should also be removed.
Individual

Don Weaver
New Brunswick System Operator
NBSO
Don Weaver
Yes
One omission which should be clarified is that the applicability section does not reference Distribution Provider and Transmission Owner, but they are referenced in the requirements. This could lead to some confusion so to clarify further, Distribution Provider and Transmission Owner should be added to the applicability section.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
1.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” Unit Auxiliary Transformers (UAT’s) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3. The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities’ UATs in Section 3.2.3 do not belong in this standard, as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT’s lack of impact on generator loadability should be considered by the SDT. A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). 2.) The term “full-load current” needs clarification in the exclusion for generator overload protection with extremely inverse characteristics.” The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that “full-load current” is understood to be the generator nameplate MVA at rated voltage 3.) The overload protection exception for “extremely inverse characteristics” should be applied for UAT’s as well if eliminating UAT’s in

its entirety (per comment #1 above) does not prove feasible. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing.
Individual
Michelle D'Antuono
Occidental Energy Ventures Corp.
n/a
n/a
No
In the course of developing PRC-025-1, the project team has abandoned its initial efforts to address cost/benefit effectiveness. Although we understand that FERC has directed a generator-related load relay standard, we do not believe that this justifies a zero-tolerance approach that may lead to an expensive relay reconfiguration or replacement. For example, a number of industry commenters have indicated that they may be required to spend capital and expense dollars on UAT protection systems – even if there is no data indicating a correlation between UAT relay actions and BES Disturbances. Along the same lines, there is no assurance

that even if the settings in PRC-025-1 are perfectly applied, that a CEA will not assess a violation should a Fault-sensing relay trip. The only level of consideration that an auditor must apply is that the relay owner must maintain “reliable fault Protection”, a highly arbitrary assessment. It is easy to see that an after-the-fact review of the triggering event would expose the owner to penalties – even if the Fault relay tripped because of some highly unusual conditions. As an example, it is well known that the proliferation of high-efficiency air conditioners has led to undervoltage waveform distortions in recent years. It is not appropriate that a Generator Owner be held accountable to rapid changes in load technologies – particularly if they make good faith efforts to accommodate the NERC standards. NERC has begun to capture the concept of risk-based compliance, and has made a commitment to proceed in this direction. This separates the treatment of entities who maintain strong internal compliance controls from those who do not. In addition, this advanced methodology relentlessly collects and assesses disturbance data to detect risk trends – identifying those which deserve the highest priority regulatory attention. Even if we hold the minority opinion, a very fundamental opportunity to advance the risk-based concept is being lost in the rush to accommodate FERC’s directives. This is a mistake in our view – and may lead to low-priority items taking precedence over more pressing issues.
Individual
David Jendras
Ameren
Ameren Compliance
Eric Scott
No
(1) We support the SERC Protection & Control Subcommittee comments and hereby include them by reference rather than repeating them all. (2) We are voting negative because this present draft expands the Option 13a and 13b language from that of draft 3 (for which we voted affirmative). This language includes ‘consequential trips’, which we believe is ambiguous, and is inconsistent with the NERC BOT, approved PRC-005-2. We request the SDT for Option 13a and 13b to only include direct trips for which there is certainty that the generator will be tripped; we believe this provides a bright line for both auditors and entities. (3) Furthermore, we neither have experience or awareness of UAT relay loadability being a cause of incorrect generator trips so there’s little justification for including the UAT in a generator loadability standard.
Individual
Thomas Breene
Wisconsin Public Service Corporation
None
Thomas Breene
No

The proposed Phase I and Phase II BES definition inappropriately applies to individual wind turbines. The standard drafting team should consider revising the applicability criteria to clearly state that PRC-025 is not meant to apply to individual wind turbines but to aggregated generation greater than 75MVA connected at a common point at 100kV or above. Changing the BES definition to exclude individual wind turbines would also address this comment.
Individual
Brett Holland
Kansas City Power & Light
Kansas City Power & Light
Brett Holland
Agree
North American Generator Forum
No
Group
City of Tacoma, Tacoma Public Utilities, Tacoma Power
Chang Choi
Yes
Are excitation transformers considered UATs? It is recommended that they not be considered UATs. In Draft 4 of PRC-025-1, under Exclusions, Tacoma Power suggests that “the following protection systems are excluded from the requirements of this standard:” be changed to something like “Protection Systems that are excluded from the requirements of this standard include, but are not limited to, the following:” On page 9 of 25 of the redlined Draft 4 of PRC-025-1, change “…shading groups those relays…” to “…shading groups of those relays…” Referring to Option 13 of Draft 4 of PRC-025-1, change “…operation of the relays…” to “…operation of the relay…” On p. 78 of 83 in redlined Guidelines and Technical Basis, consider changing “…a synchronous generation Elements…” to “…synchronous generation Elements…”
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No
1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT

relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. 2. The term “full-load current” needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? The methods to determine the generator current rating described in PRC-025 are unnecessarily complicated. It should use the lower of the generator maximum MVA rating or the GSU’s maximum rating. 3. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. This grandfathering should also be done for generation/transmission/excitation protection coordination on units that are in service as of the adoption date of the standard. 4. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which the costs incurred due to NERC requirements have already eliminated any economic rationale for having black-start facilities. 5. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. PRC-025 has all kinds of methods described on how to set these relays. It would be much easier just to “outlaw” their use on all system connected units. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. 7. PRC-025 as written does not mention the generator and generator protection ANSI standards (ANSI/IEEE C37.102 and ANSI/IEEE C50.13) that give maximum limits of overload protection. Under a sub-heading it is alluded to but they should be refered to as a major section. 8. A requirement that the protection of the unit overrides any transmission need for the unit to remain on the line should also be a major section of PRC-025. 9. In PRC-025-1 please replace “secondary” with “voltage sensing device” from Exclusions #3 on page 8. We recommend that it read “(in order to prevent false operation in the event of a blown voltage sensing device fuse)…” 10. In PRC-025-1 please add an Exclusion of Relay Types that are directional (e.g., 21, 67) toward the generator. We recommend that it read “Load-responsive protective relay elements applied directional toward the generator.”
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy

No
The NSRF is not prepared to support this Standard since there is not an approved BES definition. The risk of this Standard being applicapable to individual wind turbines (i.e., time, effort, risk of non compliance) is greater than the suggested reliability benefit, concerning dispersed power producing resources.
Group
SERC Protection and Controls Subcommittee
David Greene
No
1) In PRC-025-1 please replace “secondary” with “voltage sensing device” from Exclusions #3 on page 8. We recommend that it read “(in order to prevent false operation in the event of a blown voltage sensing device fuse)…” 2) In PRC-025-1 please add an Exclusion of Relay Types that are directional (e.g., 21, 67) toward the generator. We recommend that it read “Load-responsive protective relay elements applied directional toward the generator.” 3) In PRC-025-1 your revised Table 1 Options 13a and 13b Relay Type wording is less clear than draft 3. Please restore the draft 3 tripping action wording. We recommend that it read “Phase time overcurrent relay (51) applied at the high-side terminals of the UAT that trips the generator either directly or via an interposing auxiliary/lockout relay .” 4) In the PRC-025-1 Guidelines and Technical Basis please remove “or consequential” from the Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b) section on page 23. We recommend that it read “Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) trip of the associated generator are to be compliant with the relay setting criteria in this standard.” Such reference to ‘consequential’ trips are ambiguous and should be excluded as they were in draft 3. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Ryan Walter
Tri-State Generation and Transmission Association, Inc.
Tri-State
Luis Zaragoza
No
The Facilities section addition “Elements that connect a GSU transformer to the Tranamission system that are used exclusively to export energy directly from a BES generator generating unit or generating plant” can be interpreted to exclude a tie to a GSU transformer if the station service to the generator is served through the same tie and GSU. This same phrase is used in a

few other locations in the standard, as well. In the third item in the Exclusion section, there is no need for the phrase after the parentheses that begins “provided that the distance…” and the sentence should be ended after the parenthetical phrase, though it also seems unnecessary. We believe the rationale for Exclusion six (clause 4.1.1.2 of the C37.102-2006 IEEE Guide for AC Generator Protection) should be included in the standard in a rationale box or a footnote. The first sentence in the last paragraph on page 9, beginning with “ The table is further formatted…” does not make sense to Tri-State. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards.
Individual
Daniel Duff
Liberty Electric Power
X
X
Agree
Essential Power
No
Group
Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation suggests that the drafting team define the term "load responsive protective relay," perhaps as a "relay that responds or operates for a load current during temporary over-loading." The Bureau of Reclamation would like to thank the drafting team for a job well done!
Group
FirstEnergy
Larry Raczkowski
Yes
FirstEnergy (FE) agrees the revisions made provide clarity in the applicability between the

reliability standards of PRC-023 and PRC-025. FE agrees with the replacement of the term [generator interconnection Facility] with a more prescriptive definition, but we take exception to the use of the wording [exclusively to export] in Part 3.2.4. By using the word [exclusively], Part 3.2.4 does not take into account the operation of a pump hydro facility and other small units that use the GSU as an auxiliary power source when the unit is off-line. Also, with the word exclusively used, it could inadvertently cause a “loop hole” related to facilities intended to be in scope. To address our concern FE proposes that Part 3.2.4 be revised to read as follow: ["Elements that connect a GSU transformer to the Transmission system that are used to export energy directly from a BES generating unit or generating plant.”] Recognizing that the wording will also be used in PRC-023 applicability statement 4.2.1.1 the team should carefully consider a similar “loop hole” that may be caused by the word “export” in PRC-023. The question that needs to be considered is do the facilities need to be reviewed from a load serving perspective in PRC-023? FE’s view is that, the subject facilities when used to serve a plant auxiliary load, or pumping load would be radial to load facilities and not considered “network” facilities that is the focus of PRC-023. It’s FE’s view that from a load serving mode perspective the radial facilities do not warrant consideration and do not present a reliability risk to the BES. To better clarify that the facilities reviewed under PRC-025 can be excluded in PRC-023 the team may wish to consider the following alternative language for Part 3.2.4.: [“Elements that connect a GSU transformer to the Transmission system that are used for the sole-purpose of a BES generating unit or generating plant.”] This alternate language removes both the “exclusive” and “export” wording and may better meet the team’s intentions for how the standards supplement each other in regards to relay loadability reviews. FE views our proposed changes as clarifying changes which do not substantively alter the team’s intentions and scope of the PRC-025 and PRC-023 standards. FE appreciates the team’s careful consideration of industry comments and the revisions made in its current draft standards. We have revised our ballot position to Affirmative for the current draft of PRC-025.
Individual
Alice Ireland
Xcel Energy
NA
NA
No
1.For Table 1 description on page 8, we recommend the following wording to match the 3.2 Facilities section: The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements utilized in the aggregation of dispersed power producing resources, and Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications. 2.For Table 1 applications – recommend update to match the 3.2 Facilities Section (e.g. Add ‘Elements utilized in the aggregation of dispersed power producing resources’). 3.For Table 1 applications

– Recommend addition of Aggregating equipment for Asynchronous and Synchronous equipment (e.g. bus in a hydro plant). 4.The Phase time over current relay (51) function is missing in the Synchronous Generator application section. 5.In attachment 1 of PRC-025-1 there are some very specific guidelines on how to handle transformer taps. No such direction was ever given for PRC-023. Please clarify if the terminology used in PRC-025 also applies to PRC-023, since they are both loadability standards.
Group
North American Generator Forum Standards Review Tram
Patrick Brown
No
1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not significantly affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. 2. The term “full-load current” needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? 3. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 4. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which the costs incurred due to NERC requirements have already eliminated any economic rationale for having black-start facilities. 5. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above.
Group

DTE Electric
Kathleen Black
Agree
No
(1) Please define the term [consequential trip] as it applies to unit auxiliary transformers on page 23 of the Guidelines and Technical Basis document. Is there a timeframe where loss of the transformer must result in a trip of the generator. For example, the trip of a fuel supply transformer may take hours before it causes a loss of generation (2) It is suggested that if elements utilized in the aggregation of dispersed power producing resources are to be included in this standard, then Table 1 should be modified to include this application in order to be consistent with the other facilities listed in Section 3.2.
Individual
Scott Berry
Indiana Municipal Power Agency
NA- individual was checked and this kept coming up.
NA
No
For Exclusion number 6, IMPA would like to see clarification in the generator “full-load current” area, especially when it comes to gas turbines. Gas turbines loading changes with the air temperature and their loading can be very different from summer to winter with different loads reported to their Transmission Planner for each season. This would be a problem if the full-load current references the 100% of the gross MW capacity reported ot the Transmission Planner because the statement does not account for the different seasonal capability reported values for gas turbines. If the exclusion is referencing the full-load current based on generator nameplate, then it just needs to be referenced in the exclusion. IMPA would also like to see additional clarification in table 1 when referencing "Real Power Output". For gas turbines, two seasonal values are reported to the Transmission Planner (Summer and Winter). These two seasonal values are very different and IMPA believes the SDT needs to specify which seasonal value should be used for the Real Power output when performing the calculation.
Group
ACES Standards Collaborators
Jason Marshall
No
(1) We disagree with the inclusion of a Distribution Provider in the standard. By definition in the NERC Glossary a Distribution Provider “provides and operates the ‘wires’ between the transmission system and the end-use customer”. They do not own facilities that interconnect generators to the Bulk Electric System. This is further supported by the registry criteria which

only identify ownership of a transmission Protection System, Special Protection System, UFLS, UVLS or peak load exceeding 25 MW as reasons to register a Distribution Provider. The response to our previous comments regarding applicability of the Distribution Provider to the previously proposed PRC-023-3 R7 and R8 indicated this was an unlikely situation but was intended to avoid gaps. While we appreciate the attempt avoid gaps, this is a very obscure situation and no standard can anticipate every possible nuance. NERC has the ability within its Rules of Procedure to register an entity if facts and circumstances warrant it. If there is a DP that should be registered for additional functions and be subject to additional compliance burdens, that determination should be made through pre-existing processes and procedures and not through the applicability of a reliability standard. Furthermore, if the anticipated gap was a conceptual gap and not an actual known gap, we believe no attempt should be made to address an obscure situation that will likely never exist. The regional entities can evaluate situations, configurations and systems to determine whether a gap exists and how to proceed. It is not the role of the drafting team to create standards for every possible scenario that could lead to an event on the Bulk Electric System. The drafting team should consider revising the standard to address the majority of the situations that may arise for improper relay settings and allow the other processes and procedures to address any gaps as they arise. Furthermore, as demonstrated by the early discussion regarding the definition and registry criteria, this would actually be a registration issue and not a gap in the standard. (2) We understand that the term “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant” was used in PRC-025 because the Guidelines and Technical Basis document indicated there was a concern that a Distribution Provider may own a “generation interconnection Facility” and that the term implies ownership by the GO. We disagree with this implication and have found numerous references including November 16, 2009 Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that indicate the facility may or may not be owned by the GO. Futhermore, the original proposed definition from the report did not indicate ownership. (3) We disagree with the applicability of 3.2.5. Because “Element” is not limited to the BES by the definition, the applicability could be interpreted to include the distribution collector system. We do not believe inclusion of the distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can understand inclusion of the main GSU for a large site but not the individual collector elements. We recommend the drafting team revise the standard to remove all references, such as the unqualified use of Element (i.e without a BES adjective) to the distribution system because it does not impact the Bulk Electric System. (4) The light blue bar under Option 2c with “The same application continues on the next page with a different relay type” text in Table 1 should be removed. (5) Since the “generator interconnection Facility” term has already been established in other standards and was deemed to be understood well enough by the Project 2010-07 Generator Requirements at the Transmission Interface drafting team that a glossary term was not necessary contrary to the ad hoc report, it should be used in PRC-025 to avoid confusion and inconsistency. Confusion could arise with enforcement and compliance personnel over the use of the term “Elements that connect a GSU

transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" and how to apply the standard to the GO. This will result in the GO, NERC and Regional Entities expending additional resources on an unnecessary compliance activity that does not support reliability of the Bulk Electric System. (6) We understand that the term "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" was used in PRC-025 because the Guidelines and Technical Basis document indicated there was a concern that a Distribution Provider may own a "generation interconnection Facility" and that the term implies ownership by the GO. We disagree with this approach and have found numerous references including November 16, 2009 Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that indicate the facility may or may not be owned by the GO. Futhermore, the original proposed definition from the report did not indicate ownership. (7) There are inconsistent applications between the terms in PRC-023 and PRC-025 that are intended to apply to non-radial and radial generator interconnection Facilities. PRC-025 uses the term "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" while PRC-023 uses slight variants of the term "except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network." Some differences that should be eliminated include the appended "to the network" in the PRC-023 term, use of "Elements" in PRC-025, and use of "lines and transformers." Keeping the language of the two standards consistent will reduce the possibilities of inconsistent application of compliance personnel. (8) We do not understand how replacing "generation interconnection Facility" with a 26 word phrase is helpful or adds clarity to the standard. The Project 2010-07 drafting team already determined that "generator interconnection Facility" was a well understood term and did not imply ownership. We recommend persisting with the use of the term for clarity. We simply do not see how replacing "generator interconnection Facility" with a 26-word phrase provides additional clarity. Rather, it invites multiple interpretations, inconsistent application, and further confusion. (9) We continue to disagree with the approach of requiring a registered entity to replace all relays that cannot meet the settings of PRC-025-1 in order to comply with this standard. The standard should provide more flexibility to allow a registered entity to replace relays when they have reach the end of their useful life unless the circuit has been deemed a critical facility by another standard.
Group
Santee Cooper
S. Tom Abrams
No
The wording of Table 1 Options 13a and 13b should be changed back to the Draft 3 wording. The wording in the new draft is more ambiguous and could lead to more confusion. We agree with the SERC PCS's recommendation for this section to read "Phase time overcurrent relay (51) applied at the high-side terminals of the UAT that trips the generator either directly or via

an interposing auxiliary/lockout relay." We also feel there should be an additional item in the list of Exclusion of Relay Types to cover relay types that are directional toward the generator.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC PCS
Group
SPP Standards Review Group
Robert Rhodes
Yes
This is especially true regarding the treatment of UATs and the movement of focus to the high-side of the transformer.
Individual
Brenda Hampton
Luminant Energy Company LLC
Luminant
Brenda Hampton
No
The additional work provided by the standard drafting team has clarified the bright line between PRC-025 and 023. However, Luminant disagrees with the loadability criteria (aggregate generation) used in PRC-025 for multiple lines used for exporting generation (Figure 2 in the Guidelines and Technical Basis document).The loadability criteria is too conservative when compared to PRC-023 Requirement R1 transmission line criteria. Luminant recommends that the loadability criteria used in PRC-023 for transmission lines be part of PRC-025 for use in cases where multiple lines are used to export energy.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
#1 - The term "full-load current" needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or UAT? #2 - Deeming any and all violations of this standard to have a high violation risk factor and a severe violation

severity level seems overly harsh.
Individual
Modesto Irrigation District
Modesto Irrigation District
Modesto Irrigation District
Spencer Tacke
No
In section 3.2 "Facilities", I think it is critical that the following phrase be added at the end of the first paragraph: "..., and any generator, regardless of size or connected voltage, that has been shown to be material to the reliability of the BES". The “bright line” of 100 kV and 20 MVA is fine in general, but when it is known that a generator connected at less than 100 kV is material to the reliability of the BES, it should be included as an applicable facility for this standard. WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, past WECC studies of major outages have shown that generators connected at less than 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the 1996 outage and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV I am voting NO because I think it is critical to revise the applicability statement in section 3.2 before approving the Standard. The technical section on the settings seems fine to me, but getting the applicability correct is very important. Thank you.
Group
National Grid
Michael Jones
No
RE: Draft Standard: Page 3 of 25 under applicability should read "owns" instead of "applies." Page 7 of 25, under Generators, the 1st paragraph needs clarification regarding how to derive MVAr. When reading Attachment 1, it is evident what is being proscribed but you can't deduce that from the subject paragraph. Page 9 of 25 the last paragraph text "thoseof" needs correction. Generator Owners own relays on the transmission system beyond what is listed in Attachment 1. Generator Owners should be responsible for the relays they own on the transmission system. The Generator Owner's responsibility for loading is not limited just to relays in PRC-025, Attachment 1. RE: Implementation Plan Pages 4 and 5: "relays applicable to this standard" should be changed to either "relays to which this standard is applicable" or "relays subject to this standard" Pages 4, 5, 6 and 7: The text references relays and circuit breakers that are not shown or labeled in the figures. The figures are mislabeled. For instance the text for Fig. 2 states "Generation exported through multiple radial lines" but the drawing

above the text depicts only a single radial line. A later unlabeled figure appears to meet that description but breakers are unlabeled and relays are not depicted.

Consideration of Comments

Project 2010-13.2 Phase 2 Relay Loadability: Generation

The Relay Loadability: Generation standard drafting team thanks all commenters who submitted comments on PRC-025-1. The standard was posted for a 30-day formal comment period from June 20, 2013 through July 19, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 114 different people from approximately 93 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of changes (PRC-025-1)

The generator relay loadability standard drafting team ("SDT") made clarifying and non-substantive revisions the proposed draft of PRC-025-1 – Generator Relay Loadability during its 30-day formal comment posting of the standard and successive ballot which received 72.43% stakeholder approval. The following narrative is a summary of the non-substantive clarifications made to the above standard.

Standard

- Purpose
  - None change.
- Applicability
  - Stakeholders had concerns that in the section 3.2.4 (Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.) did not take into account station service loads served by the same Elements and would not be truly "exclusive." The drafting team added the sentence "Elements may also supply generating plant loads." To clarify the intent.
- Requirement
  - None change.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- Measures
  - None change.
- Compliance
  - None change.
- Violation Severity Levels
  - None change.
- Attachment 1
  - Revised general text to improve clarity based on stakeholder comment.
  - Add a section for parallel and multiple line configures to clarify the issues with determining settings for those possible cases.
  - Clarified “full-load current” to note that means the rated armature current of the generator.
  - Add a footnote reference to direct the reader to the basis of the overload exclusion.
  - General revisions to comport with the Applicability clarification.
  - Clarified which Options are referring to “Elements utilized in the aggregation of dispersed power producing resources.” This scenario is identified in Figure 5, but not clearly in Attachment 1, Table 1.

Guidelines and Technical Basis

- Editorial changes to match clarifications in the standard.
- Provided clarifying text about dispersed power producing resources.

Implementation Plan

- No change.

VRF/VSL Justifications

- No change.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-QuebecTransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Donald Weaver	New Brunswick System Operator	NPCC	2
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Daniel McNeeley		SERC	1
2.	Ian Grant		SERC	3
3.	Marjorie Parsons		SERC	6
4.	David Thompson		SERC	5
5.	DeWayne Scott		SERC	1
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Lee Thomas		SERC	5

Additional Member	Additional Organization	Region	Segment Selection
9. Jeff Galyon		SERC	5
10. Brenda Eberhart		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	BPA, Transmission SPC Technical Svcs	WECC	1
2. Jim Burns	BPA, Transmission Technical Operations	WECC	1
3. Steve Enyeart	BPA, Transmission Customer Service Engineering	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Louis Slade	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Crowley	Electric Transmission		1
2. Connie Lowe	NERC Compliance Policy		3
3. Mike Garton	NERC Compliance Policy		5
4. Louis Slade	NERC Compliance Policy		6
5. Jeff Bailey	Nuclear		5
6. Chip Humphrey	Fossil & Hydro		5
7. Sean Iseminger	Fossil & Hydro		5
8. Stephen Edwards	Electric Transmission		1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2. Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registerd Affiliates	RFC	5
3.		WECC	5
4. Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.		NPCC	6
6.		SERC	6
7.		SPP	6
8.		RFC	6
9.		WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chang Choi	City of Tacoma, Tacoma Public Utilities, Tacoma Power	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

9.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dan Inman	Minnkota Power Coop	MRO	1, 3, 5, 6
2.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
3.	Kayleigh Wilkerson	Lincoln Electic Systems	MRO	1, 3, 5, 6
4.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
5.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Lee Kittleson	Otter Tail Power Co.	MRO	1, 3, 5
8.	Marie Knox	Midcontinent Independent System Operator	MRO	2
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
11.	Scott Nickles	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
13.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6

10.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Steve Edwards	Dominion Virginia Power		
3.	David Greene	SERC		

11.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Patrick Brown	North American Generator Forum Standards Review Tram					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NextEra		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, llc		5
4.	Pamela Dautel	IPR-GDF Suez Generation NA		5
5.	Mikhail Falkovich	PSEG		5
6.	Dan Duff	Liberty Electric Power		5
7.	Gary Kruempel	MidAmerican Energy Company		5
8.	Don Lock	PPL Generation, LLC		5
9.	Joe O'Brien	NIPSCO		5
10.	Dana Showalter	E.ON		5
11.	William Shultz	Southern Company		5
12.	Mark Young	Tenaska, Inc		5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance Organization	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Al Eizans	Merchant Operations	RFC	5
4.	David Szulczewski	DO SEE Relay Engineering	RFC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Sofra	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative	WECC	1
4.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
7.	Mohan Sachdeva	Buckeye Power	RFC	3, 4

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	S. Tom Abrams	Santee Cooper	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bridget Coffman	Santee Cooper	SERC	1, 3, 5
2.	Rene Free	Santee Cooper	SERC	1, 3, 5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Andy Evans	Westar Energy	SPP	1, 3, 5, 6
3.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	James Nail	City of Independence Power & Light Department	SPP	3
8.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
9.	Kevin Stephan	Westar Energy	SPP	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Shanahan	National Grid (Niagra Mohawk)		1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
20.	Individual	Pamela Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
21.	Individual	Erika Doot	Bureau of Reclamation	X				X					
22.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
23.	Individual	NICOLE BUCKMAN	Atlantic City Electric Company			X							
24.	Individual	Mark Yerger	Potomac Electric Power Company			X							
25.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
26.	Individual	Michael Falvo	Independent Electricity System Operator		X								
27.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
28.	Individual	Rick Terrill	Luminant Generation Company LLC					X					
29.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
30.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
31.	Individual	Tim Brown	Idaho Power Company	X									
32.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
33.	Individual	Don Weaver	New Brunswick System Operator		X								
34.	Individual	Michelle D'Antuono	Occidental Energy Ventures Corp.					X					
35.	Individual	David Jendras	Ameren	X		X		X	X				
36.	Individual	Thomas Breene	Wisconsin Public Service Corporation			X	X	X	X				
37.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
38.	Individual	Ryan Walter	Tri-State Generation and Transmission Association, Inc.	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
39.	Individual	Daniel Duff	Liberty Electric Power					X					
40.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
41.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
42.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				
43.	Individual	Modesto Irrigation District	Modesto Irrigation District			X	X		X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

The drafting team appreciates the entities below supporting the comments supported by others. Having single sets of comments with documented supported greatly improves the efficiency of the team. This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of "Entity Name"
Liberty Electric Power	Agree	Essential Power (confirmed with entity – should have listed North American Generator Forum)
Dominion	Agree	North American Generator Forum
Kansas City Power & Light	Agree	North American Generator Forum
Tennessee Valley Authority	Agree	North American Generator Forum (NAGF)
Atlantic City Electric Company	Agree	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Agree	Pepco Holdings Inc.& Affiliates
Potomac Electric Power Company	Agree	Pepco Holdings, Inc. & Affiliates
Associated Electric Cooperative, Inc. - JRO00088	Agree	SERC PCS

1. The drafting team has made revisions to the PRC-025-1 standard and its associated documents which include addressing; (1) bright line of applicability between PRC-023-3 and PRC-025-1 by including the addition of the Distribution Provider and Transmission Owner to PRC-025-1, (2) increasing the Implementation Plan period from 48 to 60 months for applying settings where replacement is not necessary and from 72 to 84 months for replacement or removal, and (3) made clarifying revisions to the Guidelines and Technical Basis. Do you agree that the drafting team achieved the level of clarity needed for the proposed PRC-025-1 standard and the associated documents? If not or if you have any additional comment, provide specific suggestions to improve the clarity of the standard.

Summary Consideration:

Overall, the proposed PRC-025-1 standard is well received. The drafting team did not receive any comments concerning the Implementation Plan with regard to the period for implementing the requirement. There were minority comments asking for clarification on the "Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant." The drafting appended the text "Elements may also supply generating plant loads" and provided additional clarification that the intent for "exclusive" was meant for non-generation plant related station service.

Of the majority comments, approximately one quarter of individuals supported by a couple of entities remain concerned about the High Violation Risk Factor and the Severe Violation Severity Level for the only requirement. The drafting team revisited the concerns and concluded that, as written, the VRF and VSL designations adhere to NERC and FERC guidance; therefore no revisions were made.

Approximately one third of the individuals supporting comments were concerned about the impacts and burden to small Generation Owners (i.e., gensets) that are subject to the standard because of inclusion in the Applicability for Blackstart resources identified in the Transmission Operator's system restoration plan. The drafting team has been firm that these resources must meet the loadability criteria anticipated by the standard to ensure reliability during system disturbances and restoration.

About one third of individuals supported by a few comments raised concerns about the changes the drafting team made during the last revision to narrow the scope the load-responsive protective relays associated with the unit auxiliary transformer (UAT). The drafting team through this discussions concluded the most appropriate approach to address these relays was to create a clear demarcation to only apply the standard to those relays which are applied at the high-side terminals of the UAT, for which operation of the relays will cause the associated generator to trip. The drafting team, in doing so, has met the intent of the directive from FERC to address the UAT, but has not expanded the scope into low-side relays that protect items like motor control centers.

Organization	Yes or No	Question 1 Comment
North American Generator Forum Standards Review Tram	No	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not significantly affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ‘03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the “consequential” language. Also for more information, please see the section “Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)” in the Guidelines and Technical Basis. Change made. 2. The term “full-load current” needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? **Response:** The drafting team notes that the phrase “full load current” refers to

Organization	Yes or No	Question 1 Comment
		rated armature current of the generator. The drafting made a clarifying change in Attachment 1: Relay Settings, Exclusion 6. Change made. 3. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 4. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which the costs incurred due to NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP) because load-responsive protective relays may not perform as

Organization	Yes or No	Question 1 Comment
		needed to facilitate system restoration. No change made. 5. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also believes that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. The VSL is binary regardless of the size of the generating unit. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 1 Comment
Colorado Springs Utilities	No	#1 - The term "full-load current" needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or UAT? **Response:** The drafting team notes that the phrase "full load current" refers to rated armature current of the generator. The drafting made a clarifying change in Attachment 1: Relay Settings, Exclusion 6. Change made. #2 - Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also believes that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. The VSL is binary regardless of the size of the generating unit. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
ACES Standards Collaborators	No	(1) We disagree with the inclusion of a Distribution Provider in the standard. By definition in the NERC Glossary a Distribution Provider "provides and operates

Organization	Yes or No	Question 1 Comment
		the ‘wires’ between the transmission system and the end-use customer”. They do not own facilities that interconnect generators to the Bulk Electric System. This is further supported by the registry criteria which only identify ownership of a transmission Protection System, Special Protection System, UFLS, UVLS or peak load exceeding 25 MW as reasons to register a Distribution Provider. The response to our previous comments regarding applicability of the Distribution Provider to the previously proposed PRC-023-3 R7 and R8 indicated this was an unlikely situation but was intended to avoid gaps. While we appreciate the attempt avoid gaps, this is a very obscure situation and no standard can anticipate every possible nuance. NERC has the ability within its Rules of Procedure to register an entity if facts and circumstances warrant it. If there is a DP that should be registered for additional functions and be subject to additional compliance burdens, that determination should be made through pre-existing processes and procedures and not through the applicability of a reliability standard. Furthermore, if the anticipated gap was a conceptual gap and not an actual known gap, we believe no attempt should be made to address an obscure situation that will likely never exist. The regional entities can evaluate situations, configurations and systems to determine whether a gap exists and how to proceed. It is not the role of the drafting team to create standards for every possible scenario that could lead to an event on the Bulk Electric System. The drafting team should consider revising the standard to address the majority of the situations that may arise for improper relay settings and allow the other processes and procedures to address any gaps as they arise. Furthermore, as demonstrated by the early discussion regarding the definition and registry criteria, this would actually be a registration issue and not a gap in the standard. **Response:** The Distribution Provider is included to address those cases where a Distribution Provider owns load-responsive protective relays on the Elements listed in the Applicability section of the standard. This also avoids an entity having to register as a Transmission Owner for this specific condition. No change

Organization	Yes or No	Question 1 Comment
		made. (2) We understand that the term “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant” was used in PRC-025 because the Guidelines and Technical Basis document indicated there was a concern that a Distribution Provider may own a “generation interconnection Facility” and that the term implies ownership by the GO. We disagree with this implication and have found numerous references including November 16, 2009 Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that indicate the facility may or may not be owned by the GO. Futhermore, the original proposed definition from the report did not indicate ownership. **Response:** The term “generator interconnection Facility” was replaced by “3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.” to reduce confusion. The drafting team received previous questions about Transmission Facility, generator leads, and generator interconnection Facility. Also, the proposed phrasing de-emphasizes ownership of the connection since the standard is addressing ownership of the load-responsive protective relays applied on those Facilities. The drafting team made minor clarifications to the Guidelines and Technical Basis. Change made. (3) We disagree with the applicability of 3.2.5. Because “Element” is not limited to the BES by the definition, the applicability could be interpreted to include the distribution collector system. We do not believe inclusion of the distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can

Organization	Yes or No	Question 1 Comment
		understand inclusion of the main GSU for a large site but not the individual collector elements. We recommend the drafting team revise the standard to remove all references, such as the unqualified use of Element (i.e without a BES adjective) to the distribution system because it does not impact the Bulk Electric System. **Response:** The Applicability section 3.2, Facilities is constructed such that, once a generating unit or generating plant is identified as "Bulk Electric System," the "Elements" listed in sections 3.2.1 through 3.2.5 are within scope for those BES resources in section 3.2. No change made. The drafting team notes that those generators aggregated in a collector system will behave similarly for the conditions anticipated by the standard. No change made. (4) The light blue bar under Option 2c with "The same application continues on the next page with a different relay type" text in Table 1 should be removed. **Response:** The formatting has been corrected. Change made. (5) Since the "generator interconnection Facility" term has already been established in other standards and was deemed to be understood well enough by the Project 2010-07 Generator Requirements at the Transmission Interface drafting team that a glossary term was not necessary contrary to the ad hoc report, it should be used in PRC-025 to avoid confusion and inconsistency. Confusion could arise with enforcement and compliance personnel over the use of the term "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" and how to apply the standard to the GO. This will result in the GO, NERC and Regional Entities expending additional resources on an unnecessary compliance activity that does not support reliability of the Bulk Electric System.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team disagrees as the term Elements refers to load-responsive protective relays applied on the Elements listed in the Applicability sections 3.2.1 through 3.2.5 and not the "generator interconnection Facility." There should be no substantive additional resource burden on identifying these relays as they should be identified in the entity's maintenance and testing program. No change made. (6) We understand that the term "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" was used in PRC-025 because the Guidelines and Technical Basis document indicated there was a concern that a Distribution Provider may own a "generation interconnection Facility" and that the term implies ownership by the GO. We disagree with this approach and have found numerous references including November 16, 2009 Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that indicate the facility may or may not be owned by the GO. Futhermore, the original proposed definition from the report did not indicate ownership. **Response:** The term "generator interconnection Facility" was replaced by "3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads." to reduce confusion. The drafting team received previous questions about Transmission Facility, generator leads, and generator interconnection Facility. Also, the proposed phrasing de-emphasizes ownership of the connection since the standard is addressing ownership of the load-responsive protective relays applied on those Facilities. The drafting team made minor clarifications to the Guidelines and Technical Basis. Change made. (7) There are inconsistent applications between the terms in PRC-023 and PRC-

Organization	Yes or No	Question 1 Comment
		025 that are intended to apply to non-radial and radial generator interconnection Facilities. PRC-025 uses the term “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant” while PRC-023 uses slight variants of the term “except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.” Some differences that should be eliminated include the appended “to the network” in the PRC-023 term, use of “Elements” in PRC-025, and use of “lines and transformers.” Keeping the language of the two standards consistent will reduce the possibilities of inconsistent application of compliance personnel. **Response:** The drafting team crafted the language to align with each standard. The proposed PRC-023-3 standard includes “lines and transformers” because the proposed PRC-025-1 standard addresses sections 3.2.2 Generator step-up (i.e., GSU) transformer(s) and 3.2.4 Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. The phrase “to the network” will be reviewed by the drafting team upon completion of the current PRC-023-3 comment period. No change made. (8) We do not understand how replacing “generation interconnection Facility” with a 26 word phrase is helpful or adds clarity to the standard. The Project 2010-07 drafting team already determined that “generator interconnection Facility” was a well understood term and did not imply ownership. We recommend persisting with the use of the term for clarity. We simply do not see how replacing “generator interconnection Facility” with a 26-word phrase provides additional clarity. Rather, it invites multiple interpretations, inconsistent application, and further confusion. **Response:** The term “generator interconnection Facility” was replaced by “3.2.4

Organization	Yes or No	Question 1 Comment
		Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads." to reduce confusion. The drafting team received previous questions about Transmission Facility, generator leads, and generator interconnection Facility. Also, the proposed phrasing de-emphasizes ownership of the connection since the standard is addressing ownership of the load-responsive protective relays applied on those Facilities. The drafting team made minor clarifications to the Guidelines and Technical Basis. Change made. (9) We continue to disagree with the approach of requiring a registered entity to replace all relays that cannot meet the settings of PRC-025-1 in order to comply with this standard. The standard should provide more flexibility to allow a registered entity to replace relays when they have reach the end of their useful life unless the circuit has been deemed a critical facility by another standard. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
DTE Electric	No	(1) Please define the term [consequential trip] as it applies to unit auxiliary transformers on page 23 of the Guidelines and Technical Basis document. Is there a timeframe where loss of the transformer must result in a trip of the

Organization	Yes or No	Question 1 Comment
		generator. For example, the trip of a fuel supply transformer may take hours before it causes a loss of generation. **Response:** In this case, "consequential" means following as an effect, result, or outcome. No change made. (2) It is suggested that if elements utilized in the aggregation of dispersed power producing resources are to be included in this standard, then Table 1 should be modified to include this application in order to be consistent with the other facilities listed in Section 3.2. **Response:** The drafting team clarified Table 1 to align with the elements utilized in the aggregation of dispersed power producing resources as shown in Figure 5 of the Guidelines and Technical Basis and included additional discussion under the Dispersed Generation section. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Ameren	No	(1) We support the SERC Protection & Control Subcommittee comments and hereby include them by reference rather than repeating them all. **Response:** Thank you. (2) We are voting negative because this present draft expands the Option 13a and 13b language from that of draft 3 (for which we voted affirmative). This language includes 'consequential trips', which we believe is ambiguous, and is inconsistent with the NERC BOT, approved PRC-005-2. We request the SDT for Option 13a and 13b to only include direct trips for which there is certainty that the generator will be tripped; we believe this provides a bright line for both auditors and entities. **Response:** The drafting team has modified the Guidelines and Technical Basis to be consistent with the language in Attachment 1: Relay Settings, Option 13a and

Organization	Yes or No	Question 1 Comment
		13b, unit auxiliary transformer application. Change made. (3) Furthermore, we neither have experience or awareness of UAT relay loadability being a cause of incorrect generator trips so there's little justification for including the UAT in a generator loadability standard. **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Pepco Holdings Inc & Affiliates	No	1) The wording in Table 1, Options 15, 16, 18, and 19 could be interpreted to imply that in addition to the supervisory phase overcurrent elements used in communication based schemes to prevent false operation during loss of communications, that any 51 or 67 element that is intentionally armed during loss of communications would also be subject to this loadability criterion. This concept was extensively debated in the development of PRC-023. However, in PRC-023 Attachment A, Section 2.1 it specifically excludes "those elements that are only enabled during a loss of communications except as noted on Section 1.6". Section 1.6 applies only to "phase overcurrent supervisory elements (i.e. phase fault detectors) associated with current-based, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." Therefore to be consistent with PRC-023, and to not draw into scope other elements that are

Organization	Yes or No	Question 1 Comment
		intentionally armed only during loss of communications, the following bullet should be added to the list of Exclusions in Attachment 1 of PRC-025-1: "Elements that are only enabled during a loss of communications except phase supervisory elements (i.e. phase fault detectors) associated with current-based, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." **Response:** The drafting team clarified the Relay Type column language in Options 15, 16, 18, and 19 by reordering the applicable relays. Change made. 2) In the Guidelines and Technical Basis document Equations 33, 47, 51, 87, 101, 113, and 117 all use the formula I pri = S / 1.73 Vbus. However, Equations 68, 132, 155, 159, and 174 all use the formula I pri = S (conjugate) /1.73 Vbus. Also, in some of the examples the angle of the current is calculated as well, while in others only scalar quantities are used. To be technically correct, the equation for I primary is developed from the apparent power expression S = V I (conjugate). Solving for I results in I pri = S (conjugate) / 1.73 V (conjugate). But since the angle of Vbus is assumed to be zero degrees Vbus = Vbus (conjugate). Therefore the correct expression reduces to I pri = S (conjugate) / 1.73 Vbus. For consistency purposes, the same equation should be used in all examples. **Response:** The drafting team intentionally left the angle out of the equation where it is not required to simplify the example calculations. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
SERC Protection and Controls Subcommittee	No	1) In PRC-025-1 please replace "secondary" with "voltage sensing device" from Exclusions #3 on page 8. We recommend that it read "(in order to prevent false operation in the event of a blown voltage sensing device fuse)..." **Response:** The drafting team removed the phrase "blown secondary fuse" and

Organization	Yes or No	Question 1 Comment
		replaced it with "a loss of potential"). Change made. 2) In PRC-025-1 please add an Exclusion of Relay Types that are directional (e.g., 21, 67) toward the generator. We recommend that it read "Load-responsive protective relay elements applied directional toward the generator." **Response:** The drafting team notes that standard addresses those load-responsive protective relays that are applicable. The standard should not address exclusions unless the exclusion is a subset of the applicable items. No change made. 3) In PRC-025-1 your revised Table 1 Options 13a and 13b Relay Type wording is less clear than draft 3. Please restore the draft 3 tripping action wording. We recommend that it read "Phase time overcurrent relay (51) applied at the high-side terminals of the UAT that trips the generator either directly or via an interposing auxiliary/lockout relay." **Response:** See #4 below. 4) In the PRC-025-1 Guidelines and Technical Basis please remove "or consequential" from the Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b) section on page 23. We recommend that it read "Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) trip of the associated generator are to be compliant with the relay setting criteria in this standard." Such reference to 'consequential' trips are ambiguous and should be excluded as they were in draft 3. **Response to Items #3 and #4:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some

Organization	Yes or No	Question 1 Comment
		individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The drafting team thanks you for your comments; please see the above responses.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential"

Organization	Yes or No	Question 1 Comment
		language. Also for more information, please see the section “Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)” in the Guidelines and Technical Basis. Change made. 2. The term “full-load current” needs clarification in Exclusion #6 (generator overload protection with extremely inverse characteristics). Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? The methods to determine the generator current rating described in PRC-025 are unnecessarily complicated. It should use the lower of the generator maximum MVA rating or the GSU’s maximum rating. **Response:** The drafting team notes that the phrase “full load current” refers to rated armature current of the generator. The drafting made a clarifying change in Attachment 1: Relay Settings, Exclusion 6. The drafting team notes that the generator MVA and GSU transformer MVA may not always be matched. The goal of the standard is to address the maximum capability of the generator during the conditions anticipated by the standard. Change made. 3. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable was installed.

Organization	Yes or No	Question 1 Comment
		This grandfathering should also be done for generation/transmission/excitation protection coordination on units that are in service as of the adoption date of the standard. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. The drafting team notes that the concerns raised relative to relays on an Exciter Power Potential Transformer (PPT) between the generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up transformer, and auxiliary unit transformers (UAT) are within the scope of the standard. No change made. 4. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping coordination study, rather than mandate upgrades that augment the degree to which the costs incurred due to NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator’s system restoration plan (i.e., SRP) because load-responsive protective relays may not perform as needed to facilitate system restoration. No change made. 5. Regarding in particular voltage-restrained overcurrent relays, this type of

Organization	Yes or No	Question 1 Comment
		device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. PRC-025 has all kinds of methods described on how to set these relays. It would be much easier just to “outlaw” their use on all system connected units. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, “… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …” Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also believes that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. The VSL is binary regardless of the size of the generating unit. No change made. 7. PRC-025 as written does not mention the generator and generator protection ANSI standards (ANSI/IEEE C37.102 and ANSI/IEEE C50.13) that give maximum

Organization	Yes or No	Question 1 Comment
		limits of overload protection. Under a sub-heading it is alluded to but they should be refered to as a major section. **Response:** The ANSI/IEEE standards are voluntary and are generally written from an equipment-specific perspective. The drafting team notes that they do, in many cases, mention system performance, and the concerns noted in the ANSI/IEEE standards for system performance do not differ greatly from the criteria proposed in PRC-025-1. Finally, the drafting team notes that the last two bullets in the Exceptions in PRC-025-1 Attachment 1 address overload protection. 8. A requirement that the protection of the unit overrides any transmission need for the unit to remain on the line should also be a major section of PRC-025. **Response:** If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 9. In PRC-025-1 please replace “secondary” with “voltage sensing device” from Exclusions #3 on page 8. We recommend that it read “(in order to prevent false operation in the event of a blown voltage sensing device fuse)...” **Response:** The drafting team removed the phrase “blown secondary fuse” and replaced it with “a loss of potential”). Change made. 10. In PRC-025-1 please add an Exclusion of Relay Types that are directional (e.g., 21, 67) toward the generator. We recommend that it read “Load-responsive protective relay elements applied directional toward the generator.” **Response:** The drafting team notes that standard addresses those load-responsive protective relays that are applicable. The standard should not

Organization	Yes or No	Question 1 Comment
		address exclusions unless the exclusion is a subset of the applicable items. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Wisconsin Electric Power Company	No	1. We appreciate the time and effort of the SDT members to develop this important standard. **Response:** Thank you. 2. However, as presently written, this standard will apply to individual wind turbine generators and other small dispersed generators by virtue of the new BES definition. To apply the rigorous requirements of this standard to the vast numbers of wind generators (typically less than 2 MW each) will require huge resources for minimal reliability benefit. The industry's resources need to be focused on higher priorities affecting overall system reliability. To avoid this problem, we request that the Applicability be revised to include only generators rated above 20 MVA; for stations with aggregate generation over 75 MVA, the requirements should apply only to the relaying from the high-voltage transmission interconnection through the main transformer (eg, 138-34.5 kv). **Response:** The Applicability section 3.2, Facilities is constructed such that, once a generating unit or generating plant is identified as "Bulk Electric System," the "Elements" listed in sections 3.2.1 through 3.2.5 are within scope for those BES resources in section 3.2. No change made. The drafting team notes that those generators aggregated in a collector system will behave similarly for the conditions anticipated by the standard. No change made. 3. Since there is no evidence that improper relay settings on UAT's or SAT's which supply generator auxiliary loads has contributed to loss of generation during disturbances, it is highly recommended to remove these elements from

Organization	Yes or No	Question 1 Comment
		the requirements. These are lower priority risks which do not rise to the level of systemic reliability concerns. **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
PPL NERC Registered Affiliates	No	1.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." Unit Auxiliary Transformers (UAT's) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3. The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03, so extending PRC-025 applicability to UATs provides only a

Organization	Yes or No	Question 1 Comment
		hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities' UATs in Section 3.2.3 do not belong in this standard, as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT's lack of impact on generator loadability should be considered by the SDT. A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made. 2.) The term "full-load current" needs clarification in the exclusion for generator overload protection with extremely inverse characteristics." The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that "full-load current" is understood to be the generator nameplate MVA at rated voltage. **Response:** The drafting team notes that the phrase "full load current" refers to rated armature current of the generator. The drafting made a clarifying change in Attachment 1: Relay Settings, Exclusion 6. Change made. 3.) The overload protection exception for "extremely inverse characteristics"

Organization	Yes or No	Question 1 Comment
		should be applied for UAT's as well if eliminating UAT's in its entirety (per comment #1 above) does not prove feasible. **Response:** The drafting team notes that the "overload protection exception for extremely inverse characteristics" is provided by Exclusion 7 in the PRC-025-1, Attachment 1: Relay Settings and is not restricted to only the extremely inverse characteristics. No change made. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have

Organization	Yes or No	Question 1 Comment
		already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. **Response:** The drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP) because load-responsive protective relays may not perform as needed to facilitate system restoration. No change made. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This

Organization	Yes or No	Question 1 Comment
		concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also believes that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. The VSL is binary regardless of the size of the generating unit. No change made. **Response:** The drafting team continues to support the proposed standard as currently structured. The requirement allows Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Xcel Energy	No	1. For Table 1 description on page 8, we recommend the following wording to match the 3.2 Facilities section: The first column identifies the application (e.g.,

Organization	Yes or No	Question 1 Comment
		synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements utilized in the aggregation of dispersed power producing resources, and Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications. **Response:** The drafting team added the example from the Applicability 3.2.5. Change made. 2. For Table 1 applications - recommend update to match the 3.2 Facilities Section (e.g. Add 'Elements utilized in the aggregation of dispersed power producing resources'). **Response:** See #3 below. 3. For Table 1 applications - Recommend addition of Aggregating equipment for Asynchronous and Synchronous equipment (e.g. bus in a hydro plant). **Response to items #2 and #3:** The drafting team clarified Table 1 to align with the elements utilized in the aggregation of dispersed power producing resources as shown in Figure 5 of the Guidelines and Technical Basis and included additional discussion under the Dispersed Generation section. Change made. 4. The Phase time over current relay (51) function is missing in the Synchronous Generator application section. **Response:** The drafting team notes this is not a typical installation for synchronous equipment and the standard does not address the case. No change made. 5. In attachment 1 of PRC-025-1 there are some very specific guidelines on how to handle transformer taps. No such direction was ever given for PRC-023. Please

Organization	Yes or No	Question 1 Comment
		clarify if the terminology used in PRC-025 also applies to PRC-023, since they are both loadability standards. **Response:** The drafting team notes that the proposed PRC-025-1 provides clarity regarding transformer taps because the tap setting is relevant to the determination of the values used in calculating the dynamic conditions anticipated by the standard. The standard PRC-023-3 criteria is based on ratings rather than dynamic performance and thus is not impacted by transformer tap settings. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Bonneville Power Administration	No	BPA supports the addition of TO's and DP's to PRC-025 and the transfer of applicability for "lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" from PRC-023 to PRC-025. However, we are concerned that certain protective relays at the network terminal of these lines are not addressed in Table 1. We appreciate that certain relays at the network terminal, directional toward the generation (for example phase distance relays), are not challenged by the same loadability concerns as the relays at the generation terminal directional toward the network; however, these relays at the network terminal are presently required to comply with PRC-023, and we are a little skeptical that they will no longer need to comply in some way with either PRC-023 or PRC-025. It appears that they will be covered by PRC-025, but there is no mention of any requirements for compliance in Table 1. If there are really no loadability requirements for these relays, please state that in Table 1. If there are loadability requirements, please state what those are in Table 1. **Response:** The drafting team notes that relays that are responsive to load flows from the generating plant to the system are addressed by the proposed PRC-

Organization	Yes or No	Question 1 Comment
		025-1 standard and relays responsive to load flows from the system to the generating plant are not subjected to any loadability concerns and are therefore proposed to have no loadability requirement in the proposed PRC-023-3 standard. No change made. We also have a minor comment on the standard. Since PRC-023 and PRC-025 are so closely related, it would be helpful it they used the same terminology. PRC-023 uses the term, "except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network", while PRC-025 uses the term, "elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant." We would like to see the same term used in both standards. **Response:** The drafting team crafted the language to align with each standard. The proposed PRC-023-3 standard includes "lines and transformers" because the proposed PRC-025-1 standard addresses sections 3.2.2 Generator step-up (i.e., GSU) transformer(s) and 3.2.4 Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. The phrase "to the network" will be reviewed by the drafting team upon completion of the current PRC-023-3 comment period. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Indiana Municipal Power Agency	No	For Exclusion number 6, IMPA would like to see clarification in the generator "full-load current" area, especially when it comes to gas turbines. Gas turbines loading changes with the air temperature and their loading can be very different from summer to winter with different loads reported to their Transmission Planner for each season. This would be a problem if the full-load current references the 100% of the gross MW capacity reported ot the Transmission

Organization	Yes or No	Question 1 Comment
		Planner because the statement does not account for the different seasonal capability reported values for gas turbines. If the exclusion is referencing the full-load current based on generator nameplate, then it just needs to be referenced in the exclusion. IMPA would also like to see additional clarification in table 1 when referencing "Real Power Output". For gas turbines, two seasonal values are reported to the Transmission Planner (Summer and Winter). These two seasonal values are very different and IMPA believes the SDT needs to specify which seasonal value should be used for the Real Power output when performing the calculation.
Response: The drafting team notes that the phrase "full load current" refers to rated armature current of the generator. The drafting made a clarifying change in Attachment 1: Relay Settings, Exclusion 6. Change made. Seasonal variations are discussed in Attachment 1: Relay Settings under the heading "Generators." The section states: "If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard." No change made. The exclusion references full-load current (i.e., rated armature current) relating to overload, and the generator nameplate references calculations used in determining the loadability settings in Table 1. No change made.		
Modesto Irrigation District	No	In section 3.2 "Facilities", I think it is critical that the following phrase be added at the end of the first paragraph: "..., and any generator, regardless of size or connected voltage, that has been shown to be material to the reliability of the BES". The "bright line" of 100 kV and 20 MVA is fine in general, but when it is known that a generator connected at less than 100 kV is material to the reliability of the BES, it should be included as an applicable facility for this standard. WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, past WECC studies of

Organization	Yes or No	Question 1 Comment
		major outages have shown that generators connected at less than 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the 1996 outage and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV I am voting NO because I think it is critical to revise the applicability statement in section 3.2 before approving the Standard. The technical section on the settings seems fine to me, but getting the applicability correct is very important. Thank you.
Response: Generators that are demonstrated to be material to the BES will likely be declared to be BES generators under the provisions of the latest approved version of the BES definition; therefore, will be included in the applicability of the standard. No change made.		
Occidental Energy Ventures Corp.	No	In the course of developing PRC-025-1, the project team has abandoned its initial efforts to address cost/benefit effectiveness. Although we understand that FERC has directed a generator-related load relay standard, we do not believe that this justifies a zero-tolerance approach that may lead to an expensive relay reconfiguration or replacement. For example, a number of industry commenters have indicated that they may be required to spend capital and expense dollars on UAT protection systems - even if there is no data indicating a correlation between UAT relay actions and BES Disturbances. The Cost Effective Analysis Process (CEAP) in the draft 3 posting of PRC-025-1 was an initial pilot of the program for only Phase II of the CEAP. The drafting team was provided summary information which did not reveal substantive reasons for changing the way the team developed PRC-025-1. Please see the Pilot CEAP Report on the Project 2010-13.2 project page (http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx). No change made.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team continues to support the proposed standard as currently structured. The requirement allows Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. Along the same lines, there is no assurance that even if the settings in PRC-025-1 are perfectly applied, that a CEA will not assess a violation should a Fault-sensing relay trip. The only level of consideration that an auditor must apply is that the relay owner must maintain “reliable fault Protection”, a highly arbitrary assessment. It is easy to see that an after-the-fact review of the triggering event would expose the owner to penalties - even if the Fault relay tripped because of some highly unusual conditions. As an example, it is well known that the proliferation of high-efficiency air conditioners has led to undervoltage waveform distortions in recent years. It is not appropriate that a Generator Owner be held accountable to rapid changes in load technologies - particularly if they make good faith efforts to accommodate the NERC standards. **Response:** The drafting team notes that violations would be assessed on a failure to comply with the requirements of the standard, not a trip of a load-responsive protective relay subject to the standard. The drafting team contends that the description of the term “while maintaining reliable fault protection” found in the Requirement R1 rationale box adequately conveys the suggested intent. No change made. NERC has begun to capture the concept of risk-based compliance, and has made a commitment to proceed in this direction. This separates the treatment of

Organization	Yes or No	Question 1 Comment
		entities who maintain strong internal compliance controls from those who do not. In addition, this advanced methodology relentlessly collects and assesses disturbance data to detect risk trends - identifying those which deserve the highest priority regulatory attention. Even if we hold the minority opinion, a very fundamental opportunity to advance the risk-based concept is being lost in the rush to accommodate FERC's directives. This is a mistake in our view - and may lead to low-priority items taking precedence over more pressing issues. **Response:** The drafting team continues to support the proposed standard as currently structured. The requirement allows Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
National Grid	No	RE: Draft Standard: Page 3 of 25 under applicability should read "owns" instead of "applies." **Response:** The drafting team disagrees with the suggestion. Ownership is not clear that the relays are applied to the Elements listed in 3.2, Facilities. By "applying" the relay also emphasizes that an entity must demonstrate the settings are applied to the relay. No change made. Page 7 of 25, under Generators, the 1st paragraph needs clarification regarding how to derive MVAr. When reading Attachment 1, it is evident what is being proscribed but you can't deduce that from the subject paragraph.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team asserts the text is accurate and that a review of the calculations in the Guidelines and Technical Basis will provide additional clarity. No change made. Page 9 of 25 the last paragraph text "thoseof" needs correction. **Response:** The drafting team replaced "those" with "of." Change made. Generator Owners own relays on the transmission system beyond what is listed in Attachment 1. Generator Owners should be responsible for the relays they own on the transmission system. The Generator Owner's responsibility for loading is not limited just to relays in PRC-025, Attachment 1. **Response:** The drafting team agrees and notes that the Generator Owner functional entity is applicable to PRC-023. No change made. RE: Implementation Plan Pages 4 and 5: "relays applicable to this standard" should be changed to either "relays to which this standard is applicable" or "relays subject to this standard" **Response:** NERC legal staff vetted this language. No change made. Pages 4, 5, 6 and 7: The text references relays and circuit breakers that are not shown or labeled in the figures. The figures are mislabeled. For instance the text for Fig. 2 states "Generation exported through multiple radial lines" but the drawing above the text depicts only a single radial line. A later unlabeled figure appears to meet that description but breakers are unlabeled and relays are not depicted. **Response:** The drafting team notes that the "redline" version did not present the Figure changes accurately. Please see the "clean" version. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 1 Comment
Luminant Generation Company LLC	No	The additional work provided by the standard drafting team has clarified the bright line between PRC-025 and 023. However, Luminant disagrees with the loadability criteria (aggregate generation) used in PRC-025 for multiple lines used for exporting generation (Figure 2 in the Guidelines and Technical Basis document). The loadability criteria is too conservative when compared to PRC-023 Requirement R1 transmission line criteria. Luminant recommends that the loadability criteria used in PRC-023 for transmission lines be part of PRC-025 for use in cases where multiple lines are used to export energy.
Response: The drafting team thanks you for your comment and has added clarifying text to Attachment 1 (Multiple Lines) to address the multiple lines issue. Change made.		
Luminant Energy Company LLC	No	The additional work provided by the standard drafting team has clarified the bright line between PRC-025 and 023. However, Luminant disagrees with the loadability criteria (aggregate generation) used in PRC-025 for multiple lines used for exporting generation (Figure 2 in the Guidelines and Technical Basis document). The loadability criteria is too conservative when compared to PRC-023 Requirement R1 transmission line criteria. Luminant recommends that the loadability criteria used in PRC-023 for transmission lines be part of PRC-025 for use in cases where multiple lines are used to export energy.
Response: The drafting team thanks you for your comment and has added clarifying text to Attachment 1 (Multiple Lines) to address the multiple lines issue. Change made.		
Tri-State Generation and Transmission Association, Inc.	No	The Facilities section addition “Elements that connect a GSU transformer to the Tranamission system that are used exclusively to export energy directly from a BES generator generating unit or generating plant” can be interpreted to exclude

Organization	Yes or No	Question 1 Comment
		a tie to a GSU transformer if the station service to the generator is served through the same tie and GSU. This same phrase is used in a few other locations in the standard, as well. **Response:** The drafting team has clarified Applicability 3.2.4 to address this concern to permit supplying station service. Change made. In the third item in the Exclusion section, there is no need for the phrase after the parentheses that begins "provided that the distance..." and the sentence should be ended after the parenthetical phrase, though it also seems unnecessary. **Response:** The drafting team contends that this phrase is necessary to fully complete the entire thought for the exclusion. No change made. We believe the rationale for Exclusion six (clause 4.1.1.2 of the C37.102-2006 IEEE Guide for AC Generator Protection) should be included in the standard in a rationale box or a footnote. **Response:** The drafting team has added a footnote to reference the basis of the exclusion. Change made. The first sentence in the last paragraph on page 9, beginning with "The table is further formatted..." does not make sense to Tri-State. **Response:** The drafting team replaced "those" with "of." Change made. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the

Organization	Yes or No	Question 1 Comment
		northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
MRO NERC Standards Review Forum (NSRF)	No	The NSRF is not prepared to support this Standard since there is not an approved BES definition. The risk of this Standard being applicapable to individual wind turbines (i.e., time, effort, risk of non compliance) is greater than the suggested reliability benefit, concerning dispersed power producing resources.
Response: The Applicability section 3.2, Facilities is constructed such that, once a generating unit or generating plant is identified as "Bulk Electric System," the "Elements" listed in sections 3.2.1 through 3.2.5 are within scope for those BES resources in section 3.2. No change made. The drafting team notes that those generators aggregated in a collector system will behave similarly for the conditions anticipated by the standard. No change made.		
Wisconsin Public Service Corporation	No	The proposed Phase I and Phase II BES definition inappropriately applies to individual wind turbines. The standard drafting team should consider revising the

Organization	Yes or No	Question 1 Comment
		applicability criteria to clearly state that PRC-025 is not meant to apply to individual wind turbines but to aggregated generation greater than 75MVA connected at a common point at 100kV or above. Changing the BES definition to exclude individual wind turbines would also address this comment.
Response: The Applicability section 3.2, Facilities is constructed such that, once a generating unit or generating plant is identified as "Bulk Electric System," the "Elements" listed in sections 3.2.1 through 3.2.5 are within scope for those BES resources in section 3.2. No change made. The drafting team notes that those generators aggregated in a collector system will behave similarly for the conditions anticipated by the standard. No change made.		
Duke Energy	No	The relays identified in this standard are shown at the high side winding of the UAT, there are many examples at Duke Energy where these relays are omitted from the design at that location. Duke Energy is concerned as to why the time overcurrent relays at the low side main breaker are not being included in this standard. These relays are set similarly and if a low side main "load responsive" relay operated unnecessarily, the outcome is similar. The generating unit would trip offline or at best run back to a reduced load. (if possible and only if multiple buses exist with diverse loads). The purpose of the standard is to improve the BES by setting "load responsive" protective relays at a level to prevent unnecessary tripping of generators. If the UAT high side "load responsive" relay is included within this standard, then the low side main "load responsive" relay must also be included. The low side main "load responsive" relays are typically set with similar criteria as the high side "load responsive" relays. The misoperation of either relay will result in lost generation. To omit the low side main "load responsive" relay from the standard means the owner can continue to set this relay at levels that would violate the intent of the standard. Lastly, the SDT should be aware that the low side main "load responsive" relay is excluded from the protection maintenance standard.

Organization	Yes or No	Question 1 Comment
Response: Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase time overcurrent relaying applied to the low voltage terminals of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. The drafting team removed the examples of low-side relays from the Guidelines and Technical Basis as this reference is not relevant to the applicable to the applications provided in the standard. Change made.		
Santee Cooper	No	The wording of Table 1 Options 13a and 13b should be changed back to the Draft 3 wording. The wording in the new draft is more ambiguous and could lead to more confusion. We agree with the SERC PCS's recommendation for this section to read "Phase time overcurrent relay (51) applied at the high-side terminals of the UAT that trips the generator either directly or via an interposing auxiliary/lockout relay." **Response:** Beyond satisfying the directive in FERC Order No. 733, paragraph 104, the drafting team contends that applying the loadability criteria to the overall unit auxiliary transformer (UAT) protective relays aims to prevent the tripping of the UAT itself even though it is possible that some individual loads may be lost during the conditions anticipated by the standard. The drafting team clarified the Attachment 1, Table 1, Options 13a and 13b to remove the "consequential" language. Also for more information, please see the section "Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)" in the Guidelines and Technical Basis. Change made. We also feel there should be an additional item in the list of Exclusion of Relay

Organization	Yes or No	Question 1 Comment
		Types to cover relay types that are directional toward the generator. **Response:** The drafting team notes that relays that are responsive to load flows from the generating plant to the system are addressed by the proposed PRC-025-1 standard and relays responsive to load flows from the system to the generating plant are not subjected to any loadability concerns and are therefore proposed to have no loadability requirement in the proposed PRC-023-3 standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Northeast Power Coordinating Council	No	We disagree with the Drafting Team’s decision not to make the change suggested during an earlier posting (remove the following words from R1 “...while maintaining reliable fault protection.”) This phrase should be replaced and therefore suggest R1 be revised to read Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while achieving its desired protection goals.
Response: The drafting team contends that the description of the term “while maintaining reliable fault protection” found in the Requirement R1 rationale box adequately conveys the suggested intent. No change made.		
Dominion	No	While Dominion does not agree with the SDT’s decision not to make the change we suggested (to remove the following words from R1 “...while maintaining reliable fault protection.”) we appreciate that they responsed. However, we remain convinced that this phrase should be replaced and therefore suggest R1 be revised to read “Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while

Organization	Yes or No	Question 1 Comment
		maintaining reliable fault protection. achieving its desired protection goals. **Response:** The drafting team contends that the description of the term "while maintaining reliable fault protection" found in the Requirement R1 rationale box adequately conveys the suggested intent. No change made. Section 3.2 - remove the entire section (3.2, 3.2.1, 3.2.2, 3.2.3, and 3.2.4), the revised Section 3.1.1 now will cover this section. The current approach would expand on the existing definition of BES and is not acceptable. **Response:** The drafting team contends that this suggestion creates ambiguity in the Facilities that apply to the standard. Section 3.1 pertains to the entities and Section 3.2 the Facilities that are applicable to the standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Kansas City Power & Light	No	
Liberty Electric Power	No	
Manitoba Hydro	Yes	Although Manitoba Hydro is in general agreement with the revisions to the standard, we have the following comments (1) 3.2 - add the acronym [(BES)] following the words "Bulk Electric System" since this is the first instance of these words in the standard. **Response:** The drafting team agrees. Change made. (2) PRC-025-1, Attachment 1: Relay Settings, Introduction - for clarity, add a comma after the word "Facilities". **Response:** The drafting team agrees. Change made. (3) PRC-025-1, Attachment 1: Relay Settings, Introduction - for clarity, re-write the sentence as follows: "shall use one of the following [19] Options listed in

Organization	Yes or No	Question 1 Comment
		Table 1,”. **Response:** The drafting team removed the reference “1-19” for clarity. Change made. (4) PRC-025-1, Attachment 1: Relay Settings - capitalize all instances of the word “element” found throughout the attachment. **Response:** The drafting team reviewed the occurrences of “element” (lowercase) and found them to be consistent with the lower case use and not the capitalized case which infers the NERC Glossary term. No change made. (5) PRC-025-1, Section 3.1.1 - only refers to Generator Owners, yet R1 also applies to Transmission Owners and Distribution Providers. This discrepancy should be rectified. **Response:** The drafting team notes that the Transmission Owner and the Distribution Provider did not appear in the initial posting and was reported by a stakeholder, corrected and reposted in the first two days of the comment period. (6) The revisions to Section 3.2.4 and Attachment 1 use the term “export” means the transmission of electricity from one jurisdiction to a foreign jurisdiction. It is not clear why such a term would be used. Unless this was the actual intention, the term “export” should be replaced with [transmit] or [deliver]. **Response:** The drafting team contends that the term “export” is consistent with the use to refer to energy delivery from the generator to the Transmission system. No change made. (7) Implementation Plan - the chart’s Applicability section for R1 does not describe applicable entities, but instead describes a requirement. **Response:** The drafting team notes this is correct. The applicability is to the performance (i.e., time frame) for which each applicable entity must implement

Organization	Yes or No	Question 1 Comment
		the specific requirement. No change.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Tacoma, Tacoma Public Utilities, Tacoma Power	Yes	Are excitation transformers considered UATs? It is recommended that they not be considered UATs. **Response:** The drafting team notes that the concerns raised relative to relays on an Exciter Power Potential Transformer (PPT) between the generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up transformer, and auxiliary unit transformers (UAT) are within the scope of the standard. No change made. In Draft 4 of PRC-025-1, under Exclusions, Tacoma Power suggests that "the following protection systems are excluded from the requirements of this standard:" be changed to something like "Protection Systems that are excluded from the requirements of this standard include, but are not limited to, the following:" **Response:** The drafting team contends that the exclusion list specifically includes those applications that should be excluded from the requirements. No change made. On page 9 of 25 of the redlined Draft 4 of PRC-025-1, change "...shading groups those relays..." to "...shading groups of those relays..." **Response:** The drafting team replaced "those" with "of." Change made. Referring to Option 13 of Draft 4 of PRC-025-1, change "...operation of the relays..." to "...operation of the relay..." **Response:** The drafting team removed the "s" off of "relays." Change made On p. 78 of 83 in redlined Guidelines and Technical Basis, consider changing "...a

Organization	Yes or No	Question 1 Comment
		synchronous generation Elements...” to “...synchronous generation Elements...” **Response:** The drafting team corrected this occurrence and others that were also found upon review. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
FirstEnergy	Yes	FirstEnergy (FE) agrees the revisions made provide clarity in the applicability between the reliability standards of PRC-023 and PRC-025. FE agrees with the replacement of the term [generator interconnection Facility] with a more prescriptive definition, but we take exception to the use of the wording [exclusively to export] in Part 3.2.4. By using the word [exclusively], Part 3.2.4 does not take into account the operation of a pump hydro facility and other small units that use the GSU as an auxiliary power source when the unit is off-line. Also, with the word exclusively used, it could inadvertently cause a “loop hole” related to facilities intended to be in scope. To address our concern FE proposes that Part 3.2.4 be revised to read as follow: ["Elements that connect a GSU transformer to the Transmission system that are used to export energy directly from a BES generating unit or generating plant.”] **Response:** The drafting team has clarified Applicability 3.2.4 to address this concern to permit supplying station service. Change made. Recognizing that the wording will also be used in PRC-023 applicability statement 4.2.1.1 the team should carefully consider a similar “loop hole” that may be caused by the word “export” in PRC-023. The question that needs to be considered is do the facilities need to be reviewed from a load serving perspective in PRC-023? FE’s view is that, the subject facilities when used to serve a plant auxiliary load, or pumping load would be radial to load facilities and not considered “network” facilities that is the focus of PRC-023. It’s FE’s view

Organization	Yes or No	Question 1 Comment
		that from a load serving mode perspective the radial facilities do not warrant consideration and do not present a reliability risk to the BES. To better clarify that the facilities reviewed under PRC-025 can be excluded in PRC-023 the team may wish to consider the following alternative language for Part 3.2.4.: [“Elements that connect a GSU transformer to the Transmission system that are used for the sole-purpose of a BES generating unit or generating plant.”] **Response:** The drafting team appreciates FirstEnergy bringing awareness to this issue and will address these concerns when responding to stakeholder comments following the proposed PRC-023-3 standard comment period. No change made. This alternate language removes both the “exclusive” and “export” wording and may better meet the team’s intentions for how the standards supplement each other in regards to relay loadability reviews. FE views our proposed changes as clarifying changes which do not substantively alter the team’s intentions and scope of the PRC-025 and PRC-023 standards. FE appreciates the team’s careful consideration of industry comments and the revisions made in its current draft standards. We have revised our ballot position to Affirmative for the current draft of PRC-025.
Response: The drafting team thanks you for your comments; please see the above responses.		
Arizona Public Service Company	Yes	Negative vote for PRC-025-1: A high VRF is unjustified since a single unit relay setting error will have minimal impact on BES, particularly for smaller units.
Response: The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, “… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions		

Organization	Yes or No	Question 1 Comment
anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also believes that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. The VSL is binary regardless of the size of the generating unit. No change made.		
New Brunswick System Operator	Yes	One omission which should be clarified is that the applicability section does not reference Distribution Provider and Transmission Owner, but they are referenced in the requirements. This could lead to some confusion so to clarify further, Distribution Provider and Transmission Owner should be added to the applicability section.
Response: The drafting team notes that the Transmission Owner and the Distribution Provider did not appear in the initial posting and was reported by a stakeholder, corrected and reposted in the first two days of the comment period.		
Bureau of Reclamation	Yes	The Bureau of Reclamation suggests that the drafting team define the term "load responsive protective relay," perhaps as a "relay that responds or operates for a load current during temporary over-loading." The Bureau of Reclamation would like to thank the drafting team for a job well done!
Response: The drafting team notes that the phrase "load-responsive protective relay" is widely understood by industry. No change made.		
SPP Standards Review Group	Yes	This is especially true regarding the treatment of UATs and the movement of focus to the high-side of the transformer.
Response: The drafting team thanks you for your comment.		
Texas Reliability Entity	Yes	We are voting FOR this standard, subject to the following comment: (1) Most references to "Regional Reliability Organization" were correctly removed from

Organization	Yes or No	Question 1 Comment
		this draft, but one occurrence remains on page 1 of Attachment 1, third paragraph. That reference to RRO should also be removed.
Response: The drafting team thanks you for identifying the missed item. Change made.		
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Company	Yes	

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.
6. Draft 2 of the standard was posted for a 45-day formal comment period from January 25, 2013 to March 11, 2013 and an initial ballot in the last ten days of the comment period.
7. Draft 3 of the standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013 and a successive ballot in the last ten days of the comment period.
8. Draft 4 of the standard was posted for a 30-day formal comment period from June 20 to July 19, 2013 and a successive ballot in the last ten days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 4 of PRC-025-1, Generator Relay Loadability for a 30-day formal comment period and successive ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period and Initial Ballot	January 2013
30-day Formal Comment Period and Successive Ballot	May 2013
30-day Formal Comment Period and Successive Ballot	June 2013
Recirculation ballot	July 2013
BOT adoption	August 2013
File with FERC	September 30, 2013

	(regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

4. Background:

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations,

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of fullload current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

[3] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	Pickup Setting Criteria
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues with a different relay type below			
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
A different application starts on the next page				

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[4]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="4">Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators</td><td rowspan="3">Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer

If the relay is installed on the generator-side of the GSU transformer use Option 7</td><td>14a</td><td>0.85 per unit of the line nominal voltage</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>14b</td><td>Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[4]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="4">Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators</td><td rowspan="3">Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer

If the relay is installed on the generator-side of the GSU transformer use Option 8</td><td>15a</td><td>0.85 per unit of the line nominal voltage</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>15b</td><td>Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 9	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 10	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 11	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[4]	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-025-1 – Generator Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner, Transmission Owner, or Distribution Provider might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance with the PRC-025-1 standard. The period to become compliant is based on two time frames. One time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays are capable of achieving compliance with the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner, Transmission Owner, or Distribution Provider determines that its existing load-responsive protective relays require replacement or removal. The standard drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load

encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of proposed PRC-025-1.

General Considerations

The Implementation Plan period reflects consideration of the following:

1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
2. The Implementation Plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months between scheduled outages.
3. The Implementation Plan assumes that Generator Owners will stagger outages between generation units or plants based upon fleet size, operating history, and forecasted outages.
4. The Generator Owner, Transmission Owner, or Distribution Provider will need to: evaluate load-responsive protective relays applied on its Facilities; perform the applicable calculations required by the standard; and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.
5. It is necessary for the generation unit or plant to be off-line in order to make adjustments.
6. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.
7. For those load-responsive protective relays that do not require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard and schedule the work while the generation unit or plant is off-line.
8. For those load-responsive protective relays that require replacement or removal, the Generator Owner, Transmission Owner, or Distribution Provider will need time to complete the evaluation in #4 above required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.
9. The Generator Owner, Transmission Owner, and Distribution Provider will need to coordinate activities where multiple owners may need to perform its work under the standard.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1	First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load-responsive protective relays subject to the standard

Each Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after applicable regulatory approvals	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after applicable regulatory approvals	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including, but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition , shall be 100% compliant on the following dates:

<table>
<tr><th rowspan="2">Requirement</th><th rowspan="2">Applicability</th><th colspan="2">Implementation Date</th></tr>
<tr><th>Jurisdictions where Regulatory Approval is Required</th><th>Jurisdictions where No Regulatory Approval is Required</th></tr>
<tr><td rowspan="2">R1</td><td rowspan="2">Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the first day 60 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
<tr><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the first day 84 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
</table>

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	**PRC-025-1 (New)** **R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
Notes: This requirement meets the directive in FERC Order No. 733, paragraph 106 and supporting paragraphs 104, 105, and 108. A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Phase II – Relay Loadability: Generator.	

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 (Retirement) R1, Criterion 6. – "Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[1]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power megawatt (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in megavoltampere-reactive (Mvar) which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer(s) and on Elements that connect the GSU transformer(s) to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of PRC-025-1 – Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria (“Table 1”) in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner’s interconnection facility (in some cases labeled a “transmission Facility” or “generator leads”) consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term “generator interconnection Facility” consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility generally implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as “Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.” to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

This standard is applicable to Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. Elements may also supply generating plant loads. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.

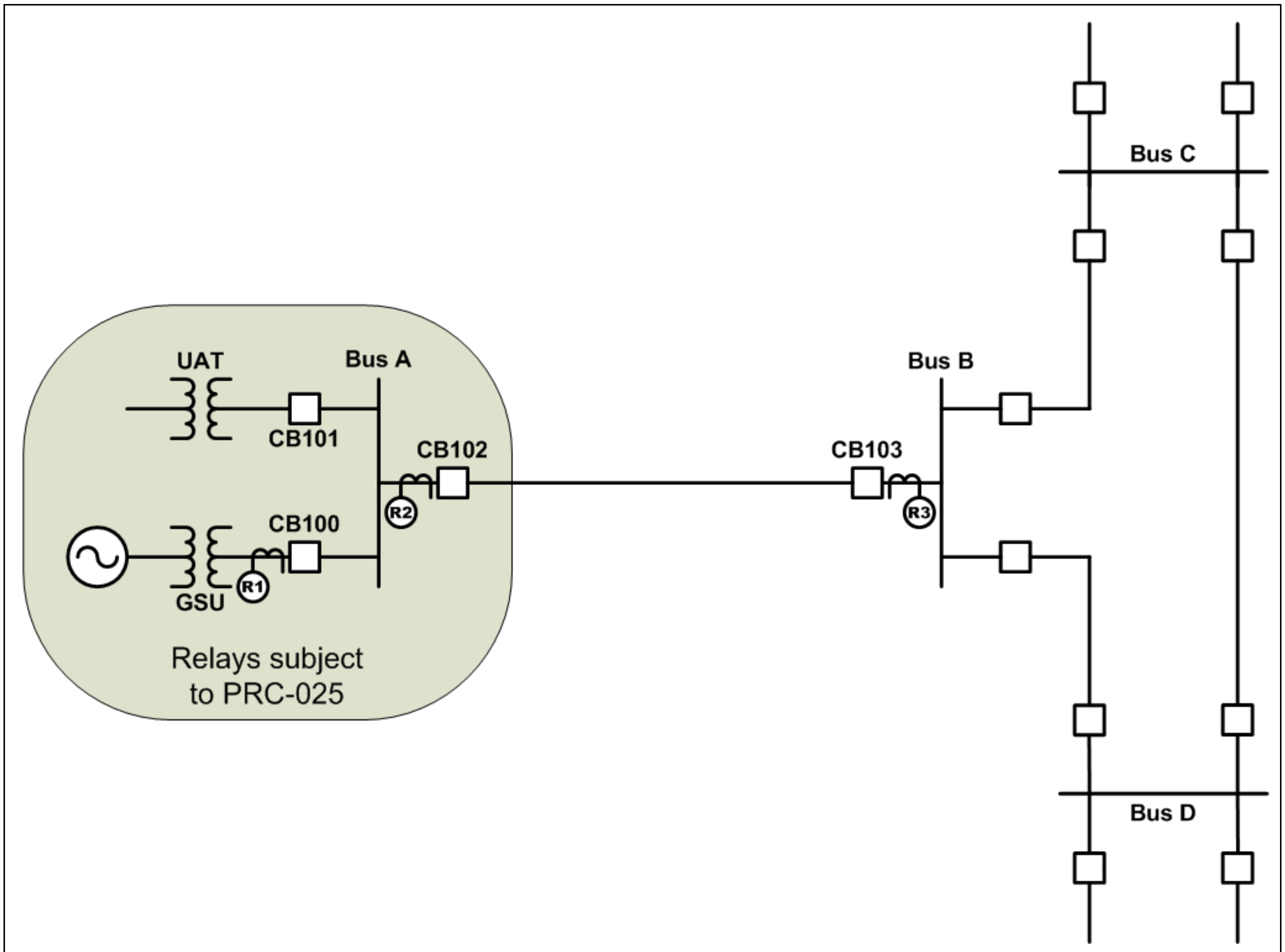


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. Elements may also supply generating plant loads. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.

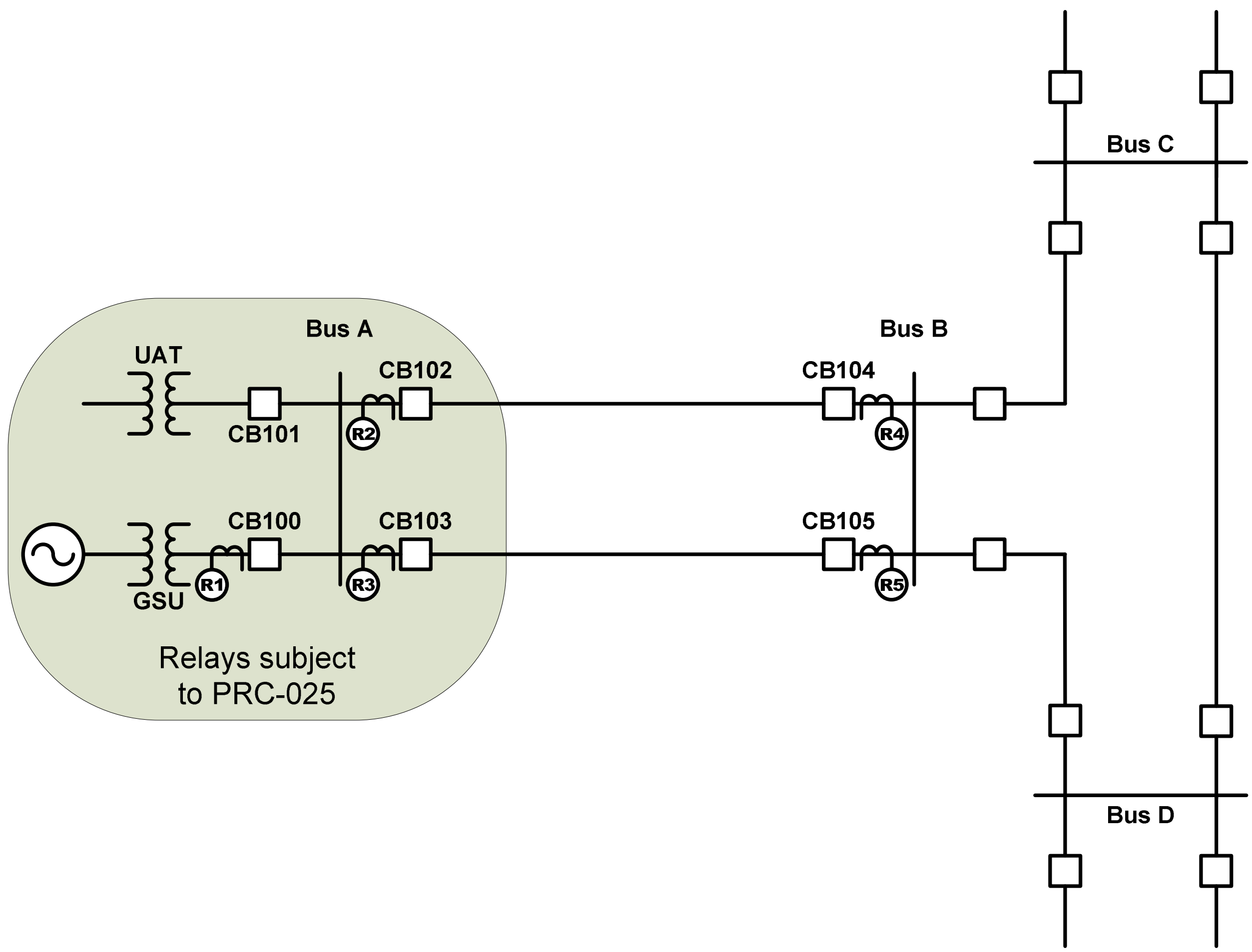


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

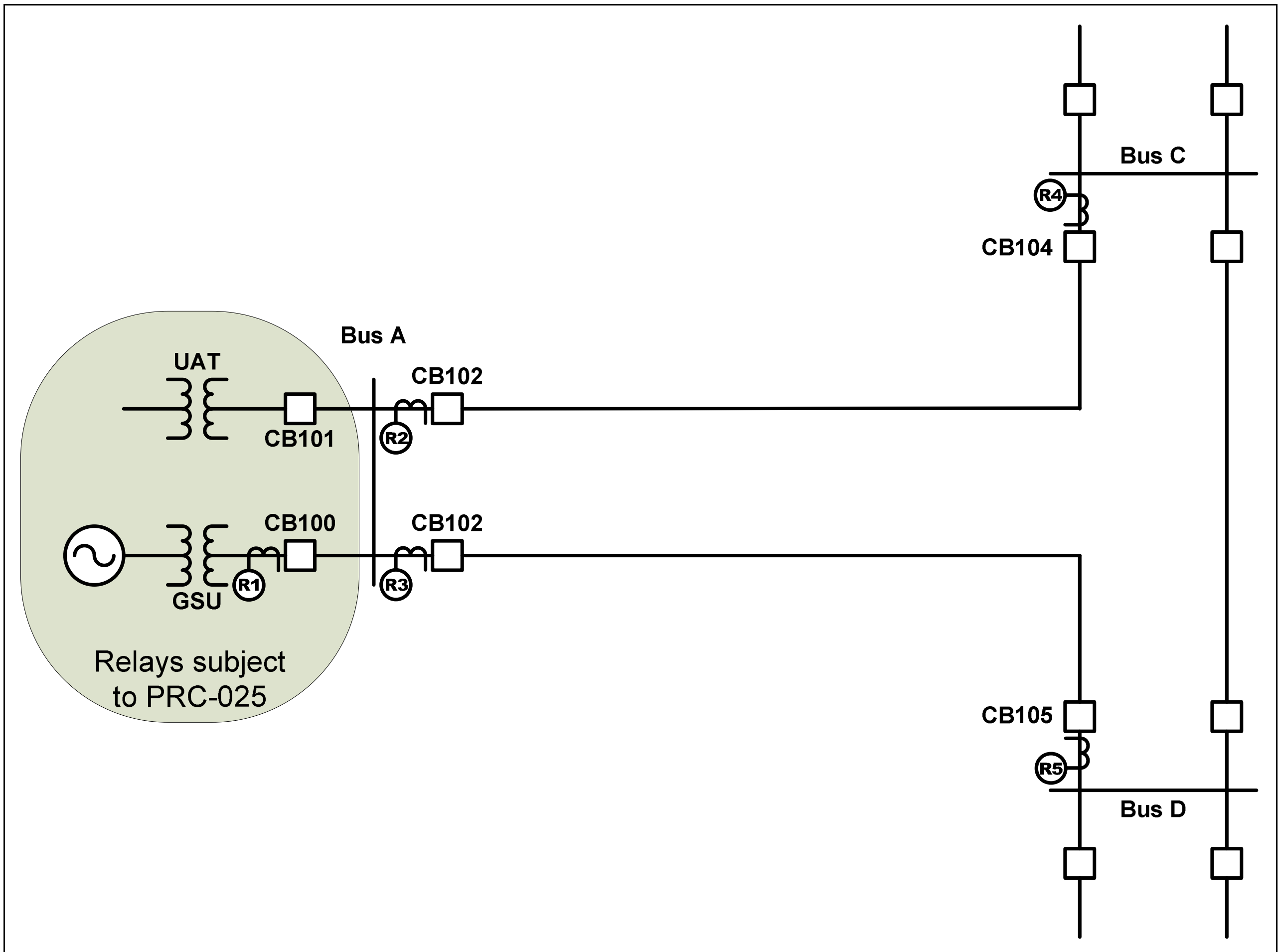


Figure 3. Generation exported through a network.

This standard is also applicable to the UAT(s) that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column "Pickup Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective elements associated with the facility are included in PRC-025.

Individual dispersed power producing resources that comprise an aggregated facility will behave similarly for the system conditions described in the Introduction above and addressed within this standard. Therefore, it is necessary to apply the criteria to each individual power producing resource.

The Elements utilized in the aggregation of dispersed power producing resources will be subjected to the effects of all dispersed power producing resources aggregated on those Elements. Therefore, the criteria applied to the individual dispersed power producing resources will also apply to the aggregation Elements.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-1. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-1. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator output.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the GSU transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the GSU transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the*

> *relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous and Time Overcurrent Relay (50/51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator(s) operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.

Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

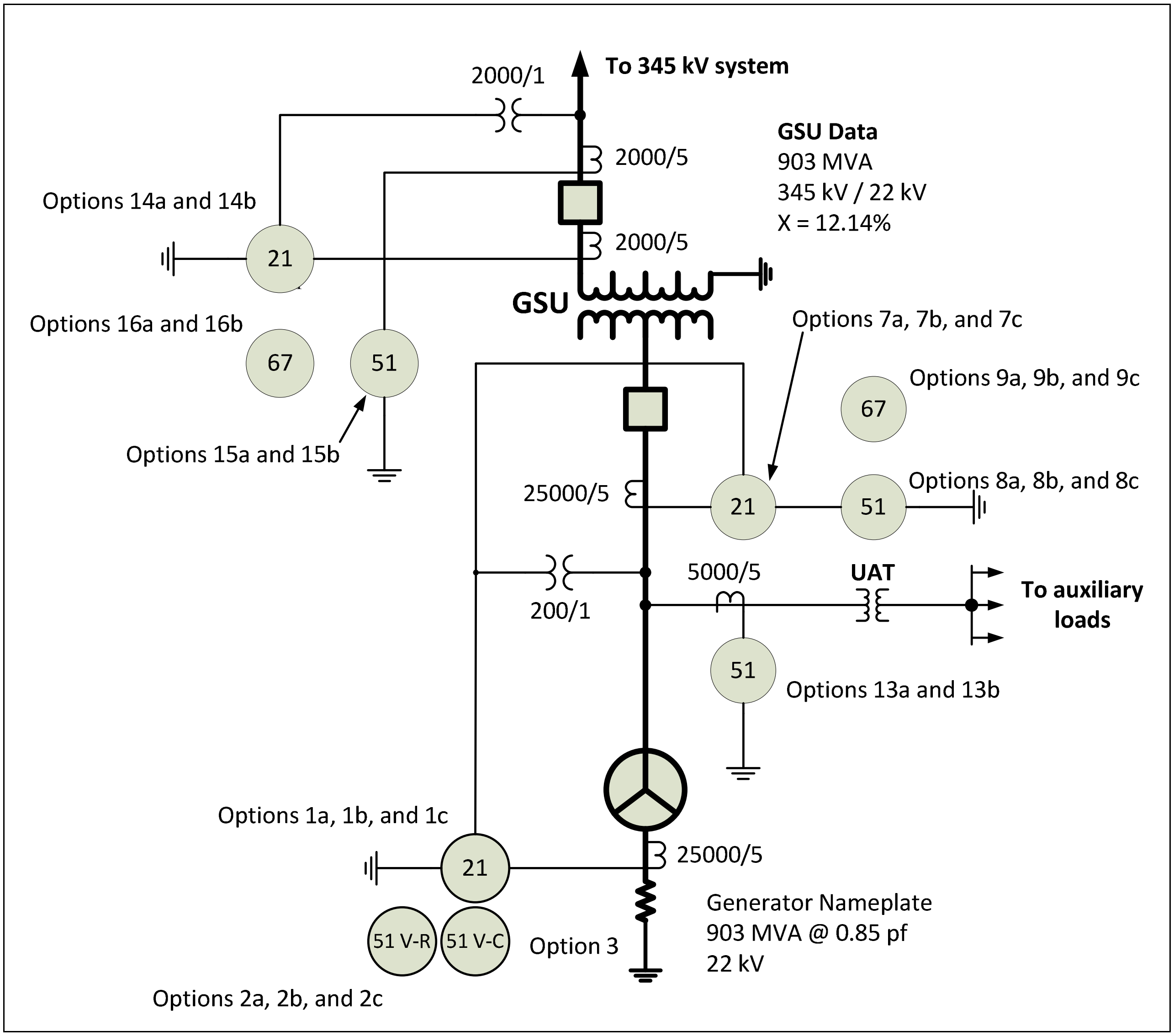


Figure 4. Relay Connection for corresponding synchronous options.

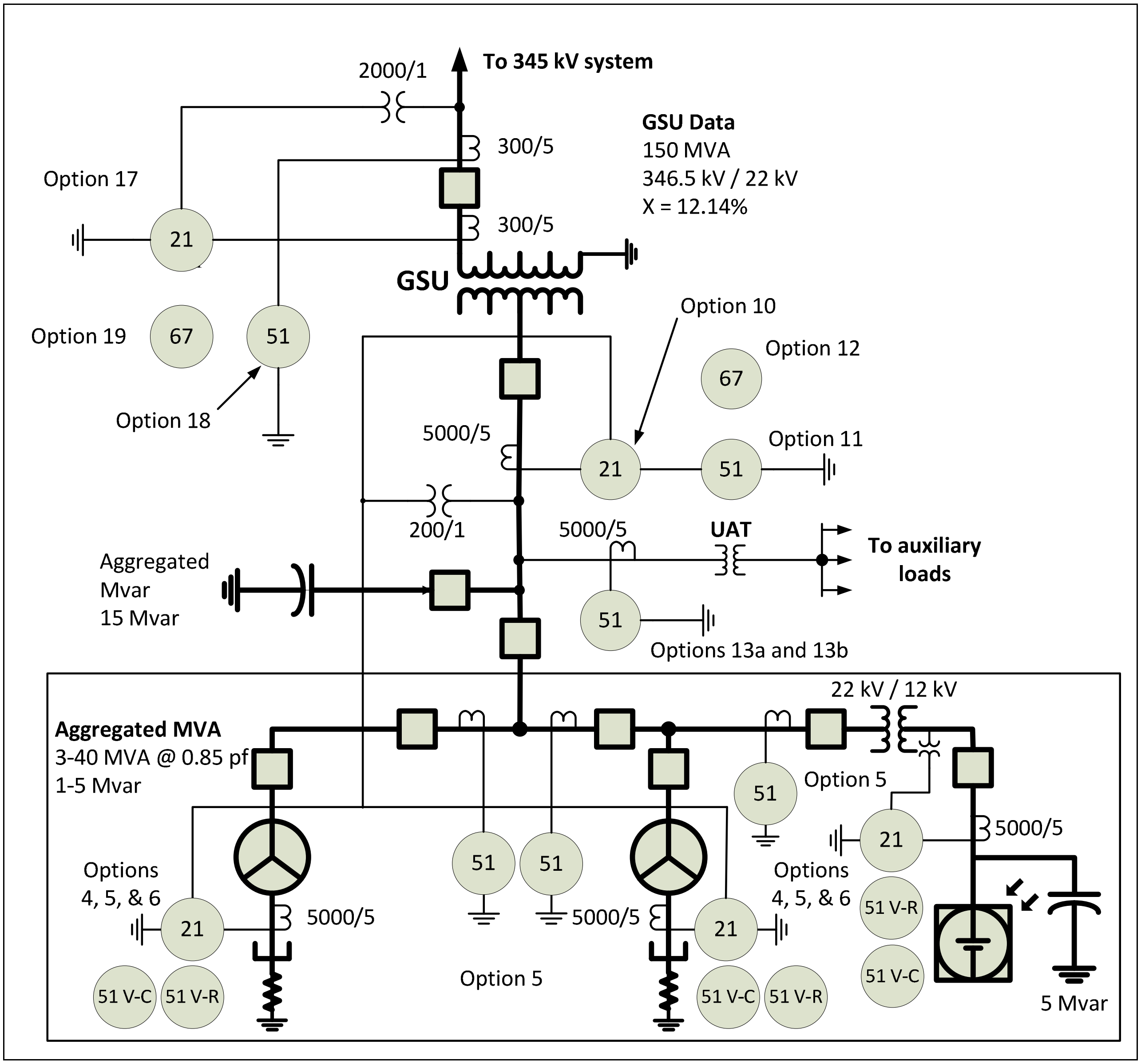


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current (e.g. rated armature current). Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current (e.g. rated armature current). Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150

percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer(s) and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for GSU transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU transformer. Where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s). The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer(s) times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the

Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) operation of the relays will cause the associated generator to trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase time overcurrent relaying applied to the low voltage terminals of the UAT are not addressed in this standard. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

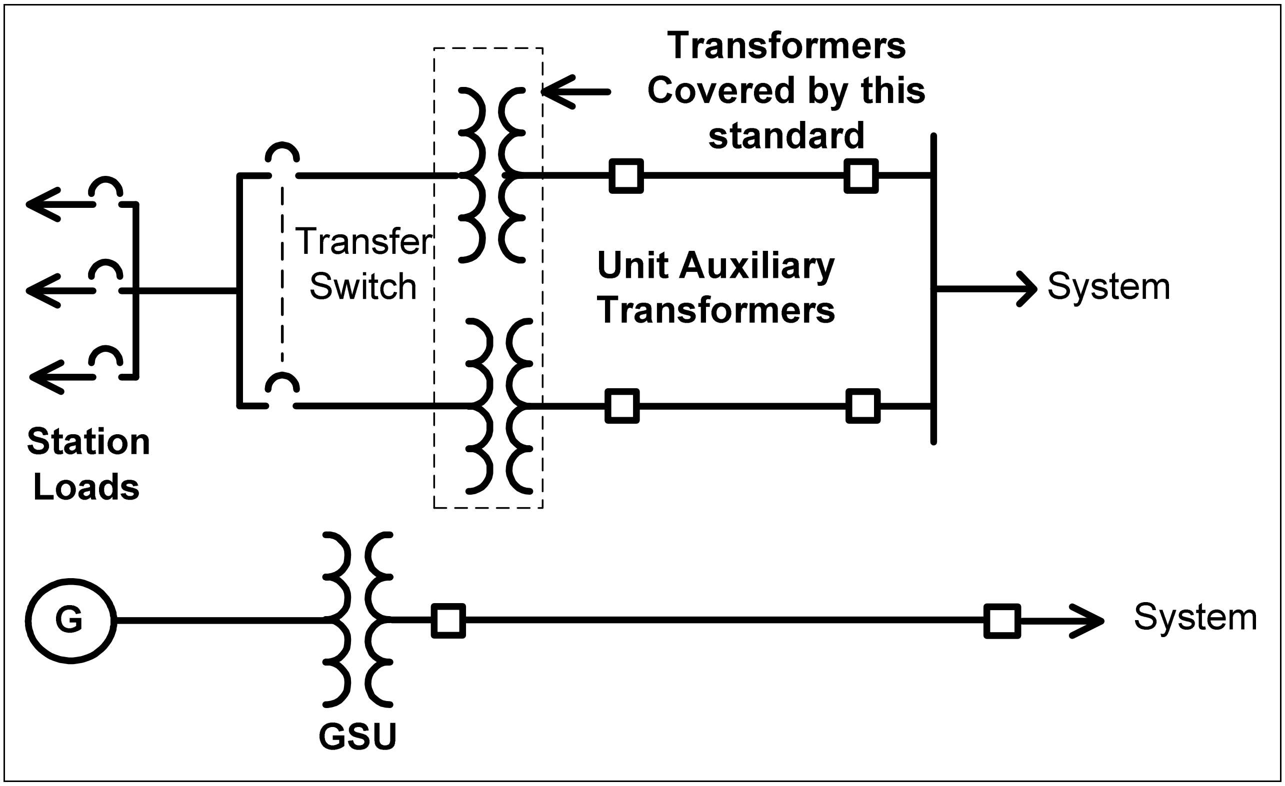


Figure-6 – Auxiliary Power System (independent from generator).

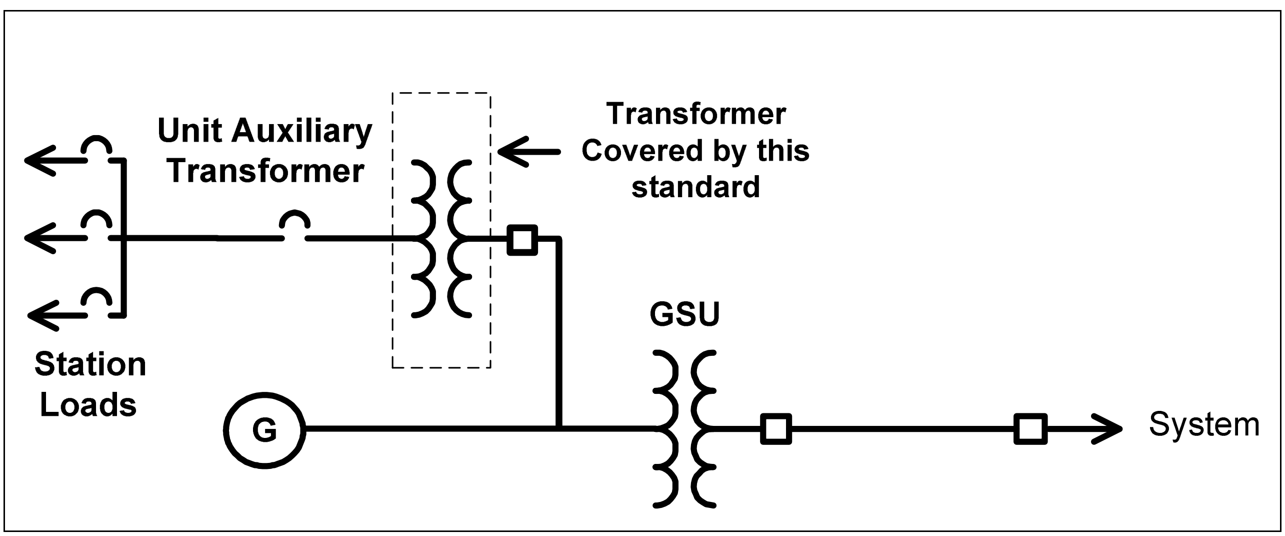


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting pickup compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.(Synchronous Generators) Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.(Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer(s) prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or

dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer(s) to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$

Example Calculations.	
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\dfrac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\dfrac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left|V_{high-side}\right|\right)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18)

$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 1b and 7b

Apparent power (S):

Eq. (19) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (23) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0^{\circ} - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

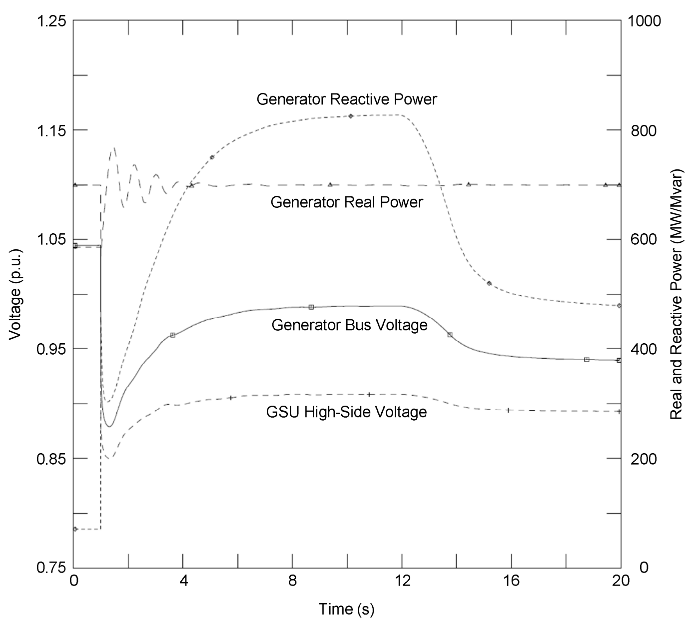
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Example Calculations: Options 1c and 7c

Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

Example Calculations: Options 1c and 7c

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 2a

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) or (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51) or (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

In this simulation the following values are derived:

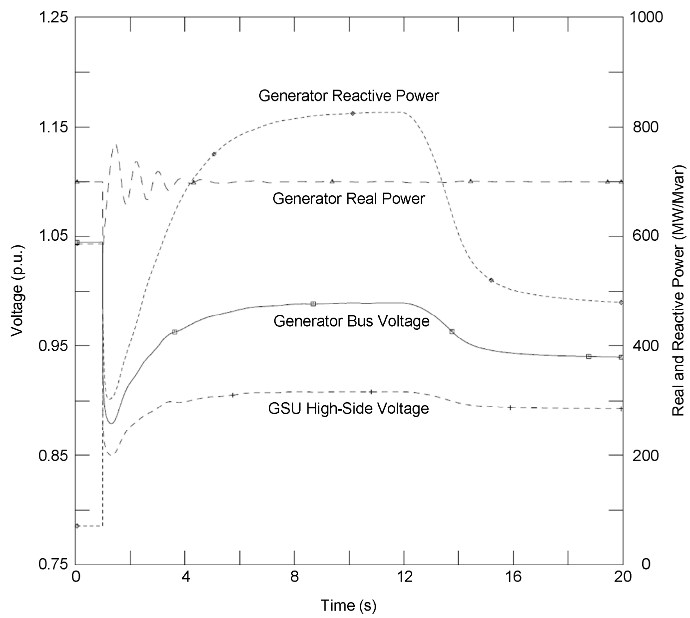
$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

Example Calculations: Option 2c

$P_{Synch\_reported} = 700.0\ MW$



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Option 2c

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 5.758\ A \times 1.15$

$I_{\sec limit} > 6.622\ A$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$V_{gen} = 21.9\ kV$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$V_{setting} < 21.9\ kV \times 0.75$

$V_{setting} < 16.429\ kV$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$P = 40\ MVA \times 0.85$

$P = 34.0\ MW$

Example Calculations: Option 4

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

Example Calculations: Option 4

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\,\Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\,\Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\,\Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\,\Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\,\Omega$$

Example Calculations: Option 5

This represents the calculation for three asynchronous generators applying a phase time overcurrent (51) or (51V-R) – voltage-restrained relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (71) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{synch}):

Eq. (72) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (73) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (74) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (75) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (76) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

Example Calculations: Options 7a and 10

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (77) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (78) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (79) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (80) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 85 to satisfy the margin requirements in Options 7a and 10:

Eq. (81) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (82) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (83) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (84) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Options 8a and 9a

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (85) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (86) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (87) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (88) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (89) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b
Options 8b and 9b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (90) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (91) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (92) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (93) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (94) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Example Calculations: Options 8b and 9b

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (95) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (96) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (97) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (98) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (99) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (100) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7^\circ\ MVA$$

Primary current (I_{pri}):

Eq. (101) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (102) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (103) $$I_{\mathrm{sec}\, limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\, limit} > 7.111\ A \times 1.15$$

$$I_{\mathrm{sec}\, limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12
This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (104) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (105) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (106) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (107) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (108) $$I_{pri-sync} = \frac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (109) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (110) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (111) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (112) $S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (113) $I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$

$$I_{pri-async} = \frac{171.1 \angle -39.2°\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (114) $I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061\angle-58.7°\,A}{\frac{25000}{5}} + \frac{4755\angle-39.2°\,A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle-56.8°\,A$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 94 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 98:

Eq. (115) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle-56.8°\,A \times 1.00$$

$$I_{\sec limit} > 9.514\angle-56.8°\,A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

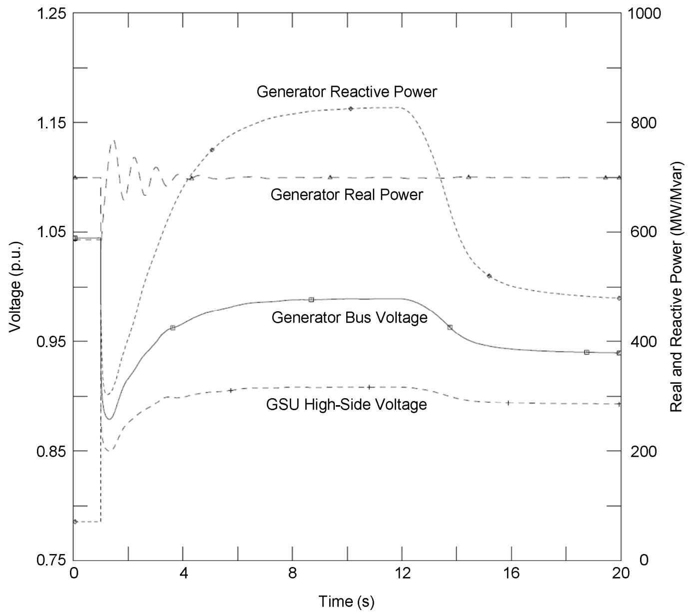
$$Q = 827.4\,Mvar$$

$$V_{bus} = 0.989 \times V_{gen} = 21.76\,kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\,MW$$

Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (116) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (117) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (118) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Options 8c and 9c

To satisfy the 115% margin in Options 8c and 9c:

Eq. (119) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 5.758\ A \times 1.15$

$I_{\sec limit} > 6.622\ A$

Example Calculations: Option10

This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (120) $P = \ 3 \times GEN_{Asych\_nameplate} \times pf$

$P = 3 \times 40\ MVA\ \ \times 0.85$

$P = 102.0\ MW$

Reactive Power output (Q):

Eq. (121) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q = 83.2\ Mvar$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (122) $V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$

$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 21.9\ kV$

Apparent power (S):

Eq. (123) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Example Calculations: Option10

Primary impedance (Z_{pri}):

Eq. (124) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (125) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (126) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (127) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12
Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (128) $P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (129) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (130) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (131) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (132) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (133) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\,A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\,A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (134) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\,A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\,A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (135) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\,MVA}{1.73 \times 13.8\,kV}$$

$$I_{pri} = 2510.2\,A$$

Secondary current (I_{sec}):

Eq. (136) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\,A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (137) $$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (138) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (139) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (140) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (141) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (142) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (143) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (144) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (145) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b
Option 14b represents the simulation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

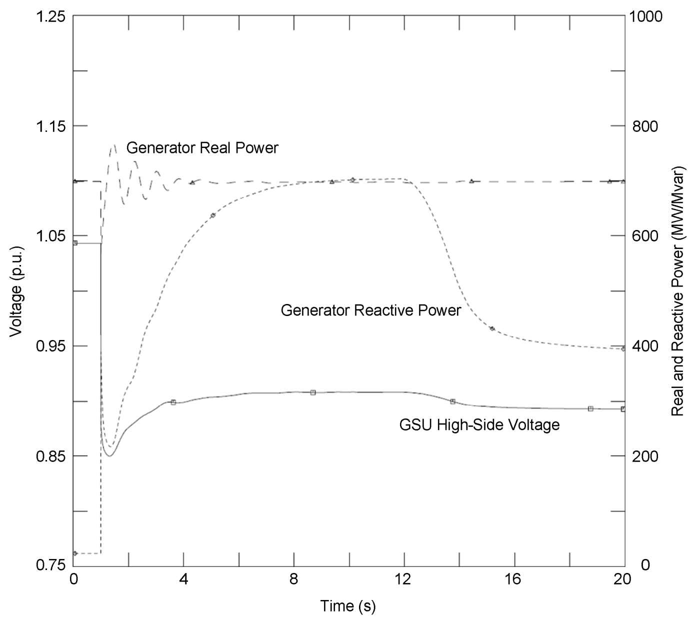
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (146) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Example Calculations: Option 14b

Primary impedance (Z_{pri}):

Eq. (147) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (148) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (149) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (150) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Option 15a represents applying a phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional overcurrent supervisory elements (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer.

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.

Real Power output (P):

Eq. (151) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (152) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (153) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (154) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (155) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\,MVA}{1.73 \times 293.25\,kV}$$

$$I_{pri} = 2280.6\angle -52.8°\,A$$

Secondary current (I_{sec}):

Eq. (156) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\,A$$

To satisfy the 115% margin in Options 15a and 15b:

Eq. (157) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\,A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\,A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for synchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Option 15b represents applying a phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

In this simulation the following values are derived:

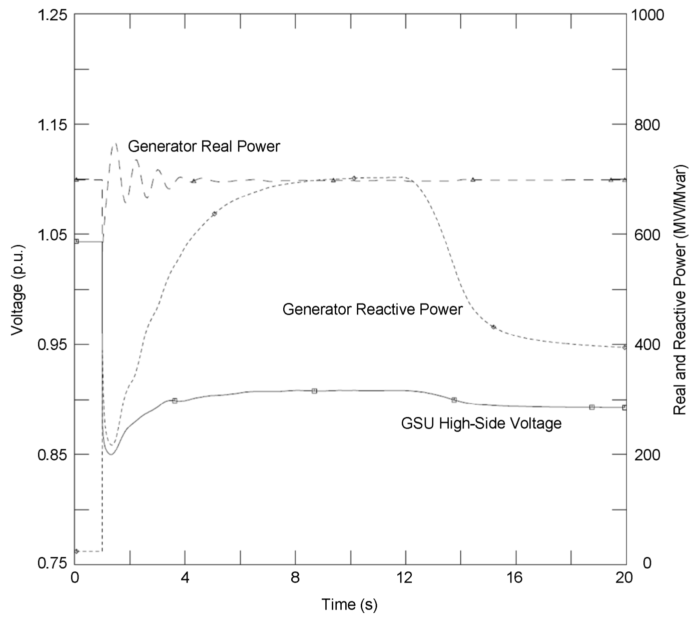
$$Q = 703.6\,Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\,kV$$

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (158) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (159) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (160) $I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\,A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (161) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 4.578\angle -45.1°\,A \times 1.15$$

$$I_{\sec limit} > 5.265\angle -45.1°\,A$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (162) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\,MVA \times 0.85$$

$$P_{Asynch} = 102.0\,MW$$

Reactive Power output (Q):

Eq. (163) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\,Mvar + 5\,Mvar + (3 \times 40\,MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\,Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (164) $V_{bus} = 1.0\,p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\,kV$$

$$V_{gen} = 345.0\,kV$$

Apparent power (S):

Eq. (165) $S = P + jQ$

Example Calculations: Option 17

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (166) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (167) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (168) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (169) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

Example Calculations: Option 17

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for three asynchronous generation Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.) that is applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, Option 19 may also be applied here for the phase directional time overcurrent relays (67) directional toward the Transmission system for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (170) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (171) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (172) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (173) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (174) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 18 and 19

$$I_{pri} = \frac{131.6\angle -39.2° \; MVA}{1.73 \times 345 \; kV}$$

$$I_{pri} = 220.5 \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (175) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2° \; A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2° \; A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (176) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2° \; A$$

End of calculations

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on "pass-fail" or a binary condition. The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on “an applied load-responsive protective relay” in accordance with Attachment 1: Relay Settings.

EXHIBIT G

Standard Drafting Team Roster

Team Roster

Project 2010-13.2 Generator Relay Loadability

	Participant	Entity
Chair	Charles W. Rogers	Consumers Energy
Member	Jeff Billo	ERCOT
Member	S. Bryan Burch, P.E.	Southern Company
Member	Steven Hataway	Florida Power and Light Company
Member	Jonathan Hayes	Southwest Power Pool, Inc.
Member	Mike Jensen	Pacific Gas and Electric Company
Member	Sudhir Thakur	Exelon Generation
Member	Joe T. Uchiyama	U.S. Bureau of Reclamation
Member	Benson Vuong	Salt River Project
Member	David Youngblood	Luminant Energy
NERC staff	Scott Barfield-McGinnis (Standard Developer)	North American Electric Reliability Corporation
NERC staff	Phil Tatro (Technical Advisor)	North American Electric Reliability Corporation

Version	Date	Description
1.0	6/12/2012	Initial posting.
2.0	8/17/2012	Removed Omar Avendano and Michael J. Putt (resigned) Added Steven Hataway and David Youngblood (SC appointed 8/9/2012)
3.0	3/15/2013	Corrected Mr. Thakur's entity name
4.0	5/23/2013	Xiaodong Sun, Ontario Power Generation resigned effective 4/30/2013

<table>
<tr><th colspan="2">Project 2010-13.2 Interpretation Drafting Team Biographies</th></tr>
<tr><th>Member</th><th>Bio</th></tr>
<tr><td>Charles W. Rogers (Chair)

Principle Engineer - Regulatory and Compliance

Consumers Energy
1945 West Parnall Road
Jackson, Michigan 49201
charles.rogers@cmsenergy.com</td><td>Mr. Rogers has spent the bulk of his career since 1978 being responsible for application of protective relaying to the transmission and distribution systems, and is currently responsible for managing compliance to the NERC Reliability Standards for the "wires" portion of Consumers Energy.

He chaired the NERC System Protection and Control Task Force from its inception in 2004 through 2008, continues to be a member of its successor group, the NERC System Protection and Control Subcommittee, and was a member of the NERC Planning Committee in 2009. He chaired the East Central Area Reliability (ECAR) council investigation into the August 14, 2003 blackout, the ECAR Protection Panel for several years, and the ReliabilityFirst Corporation (RFC) Protection Subcommittee from RFC's formation in 2006 through July 2012.

Mr. Rogers is fully engage in NERC activities which have included being a member of the "Phase II Standard Drafting Team" from 2005 to 2006, chaired the standard drafting teams that developed NERC Reliability Standards PRC-023-1 and PRC-023-2, and currently chairs the standard drafting teams assigned to Projects 2007-17 – Protection System Maintenance and Project 2010-13.2 – Generator Relay Loadability. At RFC, he also chaired the standard drafting teams that developed the Regional Reliability Standard PRC-002-RFC-01 and the Regional Reliability Standard addressing Special Protection Systems which was indefinitely suspended by the RFC Board of Directors.

Mr. Rogers received a Bachelor of Science in Electrical Engineering degree from Michigan Technological University in Houghton, Michigan in 1978. He is also a member of IEEE Standards Coordinating Committee 21 and was a key member of the working groups that developed IEEE 1547, IEEE 1547.2, and IEEE 1547.4 standards. Mr. Rogers is a registered Professional Engineer in the State of Michigan and is an IEEE Senior Member.</td></tr>
<tr><td>Jeff Billo

Manager, Transmission Planning

ERCOT
2705 West Lake Drive
Taylor, TX 76574
jeff.billo@ercot.com</td><td>Mr. Billo is currently oversees the near-term and long-term transmission planning efforts at ERCOT, including both steady-state and stability analysis. Mr. Billo's career spans nine years at ERCOT during which time he supervised over 300 generation interconnection projects. He received a Bachelor of Science in Mechanical Engineering degree from LeTourneau University in Longview, Texas in 1997 and a Master of Science in Electrical Engineering from the University of Texas at Austin in Austin, Texas in 2003.</td></tr>
<tr><td>S. Bryan Burch, P.E.

Senior Engineer

Southern Company
42 Inverness Parkway
Birmingham, AL</td><td>Mr. Burch has 24 years experience in industrial control systems and power generation plants. His work experience include generator control systems, excitation, and turbine systems, power generation plant design, protective relaying, and technical support and services. Mr. Burch's career includes extensive experience in hydro, fossil, simple and combined cycle generating plants.</td></tr>
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Project 2010-13.2 Interpretation Drafting Team Biographies	
Member	**Bio**
sbburch@southernco.com	Mr. Burch received a Bachelor of Science in Electrical Engineering degree from the University of South Carolina in Columbia in 1989 and a Master of Science in Electrical Engineering degree from the University of Alabama at Birmingham in Birmingham, Alabama in 2011. Mr. Burch is a registered Professional Engineer in the State of Alabama.
Steven Hataway, P.E. Principal Engineer NextEra Energy - Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408 steven_s_hataway@fpl.com	Mr. Hataway is a principal engineer with 21 years of electric power experience. He has been in Florida Power and Light's (FPL) Design and Standards – Settings Group for 13 years and has developed settings for generation, transmission line, and transmission and distribution substation protective relays. Prior to joining the Settings Group, Mr. Hataway worked in the Protection & Control (P&C) Department as a relay component team engineer, providing field support for protective relay related issues. He also worked as a field engineer testing and troubleshooting protective relay schemes related to generation, transmission line, and transmission and distribution substation protective relays. He started his career at FPL at the Research & Evaluation Laboratory performing mechanical, electrical, and thermal evaluations of power system components. Mr. Hataway received a Bachelor of Science in Electrical Engineering degree from Mississippi State University in Starkville, Mississippi in 1992 and is a registered Professional Engineer in the State of Florida.
Jonathan Hayes Senior Compliance Engineer Southwest Power Pool, Inc. 201 Worthen Drive Little Rock, AR 72223 jhayes@spp.org	Mr. Hayes has seven years of electric power industry experience as a NERC reliability standards development engineer, planning engineer, and operation engineer. His current role provided him compliance knowledge and experience through the implementation and ongoing management of processes necessary for Southwest Power Pool's (SPP) corporate-wide programs that ensure adherence to continent-wide and regional Reliability Standards as well as SPP's commercial business practice standards. Mr. Hayes has experience in the development, refinement, maintenance, communication, training, and implementation of continent-wide and regional Reliability Standards and policies which came from his standards development role and through working with SPP, its members, and NERC Registered Entities. His planning experience includes the study and analysis for generation interconnections, long-term transmission service requests, and expansion planning. He gained experience in operations through developing and supporting available flowgate and transmission capacity calculations used in tariff administration, and as a member to the Congestion Management Process Working Group (NERC Project 2009-10), Available Transfer Capability Coordination Task Force, and Transmission Reliability Margin Task Force. Before joining Southwest Power Pool he attended Arkansas Tech University. Mr. Hayes received a Bachelor of Science in Electrical Engineering degree, a

Project 2010-13.2 Interpretation Drafting Team Biographies	
Member	**Bio**
	Bachelor of Science in Nuclear Technology degree, and a minor in mathematics from Arkansas Tech University in Russellville, Arkansas in 2005. Over his career, he has participated in the Generator Relay Loadability (NERC Project 2010-13.2) and the Bulk Electric System Definition (NERC Project 2010-17) drafting teams, represented the SPP region on various NERC committees and subcommittees (e.g., Planning Committee, System Analysis and Modeling Subcommittee), and gained consensus within SPP and its members on comments in regards to NERC Reliability Standards and other processes under development.
Mike Jensen Supervising Protection Engineer Pacific Gas and Electric Company 487 W. Shaw Fresno, Ca, 93704 mxj3@pge.com	Mr. Jensen has 21 years of experience in the power industry in transmission protection, substation design, generation protection, and nuclear power plant maintenance/design at Diablo Canyon Power Plant. His present position involves managing group workload and providing technical guidance for 11 Protection Engineers. Mr. Jensen has extensive experience with all forms of protection schemes from distribution feeder protection, to transmission high speed communication assisted schemes, transmission transformer protection and generation protection. This includes protection scheme design, performing coordination studies, providing relay settings, and field support. He is the PG&E Protection Lead for transmission interconnected generation projects, specifying interconnection requirements and testing for interconnecting into the PG&E system which has over 12,000 MW of proposed photo-voltaic generation presently being studied or interconnected. Mr. Jensen previously served six years in the U.S. Navy on board nuclear submarines as a nuclear power plant operator and technician. He received a Bachelor of Science in Electrical Engineering degree from California Polytechnic University, San Luis Obispo, California in 1992 and is a registered Professional Engineer in the State of California.
Xiaodong Sun, P.E. Senior Engineer – Technical Compliance Ontario Power Generation, Inc. 14000 Niagara Parkway, RR#1 Niagara on the lake, Ontario Canada L0S 1J0 Xiaodong.sun@opg.com	Mr. Sun is a Senior Engineer in Plant Engineering Service of Ontario Power Generation (OPG) Inc. and has 20 years of experience in the power system industry. His primary responsibility at OPG is to handle connection assessments of OPG's new or modified generation connections and to ensure the connections meet the requirements of power system Reliability Standards from regulatory agencies including NERC. Prior to joining OPG, Mr. Sun worked for six years at Hydro One Networks Inc as Senior Protection and Control (P&C) Engineer, seven years at two thermal stations, Shajiao "B" Power Station and Liancheng Power Plant located in China, as a Protection and Control supervisor. His experience there included developing protection standards and commissioning procedures, managing P&C capital projects, and commissioning and troubleshooting P&C systems.

Project 2010-13.2 Interpretation Drafting Team Biographies	
Member	**Bio**
	Mr. Sun received a Bachelor of Science in Electrical Power Engineering degree from North China Electrical Power University, China in 1984 and Master of Science in Control Engineering degree from Lakehead University, Canada in 2000. He is a registered Professional Engineer in the Province of Ontario and a member of IEEE Power and Energy Society.
Sudhir Thakur, P.E. Senior Staff Engineer Exelon Generation 200 Exelon Way Kennett Square, PA 19348 sudhir.thakur@exeloncorp.com	Mr. Thakur is a Senior Staff Engineer with Exelon Generation for the last 15 years. He is a subject matter expert (SME) for the Protection area for Exelon. In this role, he provides corporate oversight and governance for Protection including disturbance analysis as well as some auxiliary power system studies for Exelon's nuclear units. He is also a corporate SME for compliance with NERC Protection and Control (PRC) Reliability Standards. Prior to joining Exelon, Mr. Thakur worked as supervising electrical engineer for Raytheon Engineers and Constructors where he was involved with the design and engineering of nuclear and non-nuclear generating facilities and switchyards for 18 years. His experience also includes three years as an engineer with National Thermal Power Corporation (NTPC) Ltd, India, in their Corporate Contracts Group, managing contracts for NTPC's new coal fired power plants. Mr. Thakur received a Bachelor of Science in Electrical Engineering degree and a Master of Business Administration degree from Panjab University, India in 1974 and 1976 respectively. He also received a Master of Science in Electrical Engineering degree from Drexel University, Philadelphia, Pennsylvania in 1987 and is a registered Professional Engineer in the Commonwealth of Pennsylvania. He also holds an American National Standards Institute (ANSI) 3.1 Senior Reactor Operator Certification for Management. Mr. Thakur is a member of the Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society, a member of the IEEE Power System Relaying Committee, and an active participant in IEEE Nuclear Power Engineering Committee. He is the chair of the IEEE Protection System Relay Committee (PSRC) J5 working group.
Joe T. Uchiyama Senior Electrical Engineer Federal Bureau of Reclamation MC: D-8440, PO Box 25007 Denver Federal Center Denver, CO 80225-0007 juchiyama@usbr.gov	Mr. Uchiyama has more than 33 years experience with the United States Bureau of Reclamation. His experience has included projects in power system analysis, control and, design; pumping plants up to 65,000 hp; hydraulic power plants, one of which is currently up-grading protection of 825 MVA units (six split stator windings per phase); and transmission line protection through 500 kV. He was also involved numerous witness tests of power circuit breakers and Generator step-up transformers up to 500 kV class at domestic and foreign factories. Other professional works include numerous power engineering activities as a member of industry relay working groups, subcommittees, and the main committee of Power System Relaying Committee of the Institute of Electronic and Electrical Engineers Power and Energy Section which Mr. Uchiyama

Project 2010-13.2 Interpretation Drafting Team Biographies	
Member	**Bio**
	chaired the C37.101-2006 working group. He is also a member of Western Electricity Coordination Council (WECC) Regional Relay Working Group, standard drafting team member of WECC-0059 in 2010, member of SC3-National Safety Code from 1990 through 1994, and a member of NERC's Special Protection and Control subcommittee since 2006. Mr. Uchiyama received a Bachelor of Science in Electrical Engineering degree from the University of New Mexico in Albuquerque, New Mexico in 1980. He is a registered Professional Engineer in the State of Colorado.
Benson Giang Vuong, P.E. Executive Engineer Salt River Project Mail Station POB003 P.O. Box 52025 Phoenix, AZ 85072-2025 gxvuong@srpnet.com	Mr. Vuong has 27 years of electric power industry experience. He has been in the Salt River Project (SRP) System Protection Group for 22 years and has designed installations, developed settings, and provided field support for generation, transmission, and distribution substation protective relays. Prior to joining the System Protection Group, Mr. Vuong worked five years in the Transmission Planning Department at SRP. He studied the near-term transmission plans including both steady-state and stability analysis. Mr. Vuong received a Bachelor of Science in Electrical Engineering degree and a Master of Science in Electrical Engineering degree from the Arizona State University in Tempe, Arizona in 1986 and 1991, respectively. He is a registered Professional Engineer in the State of Arizona.
David Youngblood, P.E. Project Manager Luminant – Contract Engineer 1601 Bryan Street EP24-040B Dallas, Texas 75201 dyoungb2@yahoo.com	Mr. Youngblood retired this year from Luminant; however, he continues to serve as a Project Manager under contract dedicating his full attention and extensive experience to NERC standard development projects. In addition to developing this standard, he provided valuable knowledge and expertise on other NERC projects which include Project 2007-17 (Protection system Maintenance and Testing) and Project 2007-09 (Generator Verification). Mr. Youngblood has more than 40 years of experience in the electric power industry while working for Luminant and its predecessor companies. His early career was concentrated in transmission system protection which includes transmission system studies, relay coordination, field support, and event analysis. For the last 30 years, he served as an electrical subject matter expert (SME) and supervisor of field support and relay testing for generating facilities. These responsibilities include the management of the conceptual designs for generation plant and switchyard relaying; calculation of relay settings; all automatic voltage regulator (AVR), power system stabilizer (PSS), and excitation system testing; analysis of relay operations and reporting; coordination of special protection system (SPS) review and installation; and providing comments for proposed NERC Reliability Standards under development and the Electric Reliability Council of Texas (ERCOT) protocol revision requests. Mr. Youngblood received his Electrical Engineering degree from The University

Project 2010-13.2 Interpretation Drafting Team Biographies	
Member	**Bio**
	of Texas at Arlington in Arlington, Texas in 1979 and a Master of Business Administration from The University of Texas at Tyler in Tyler, Texas in 2005, and is a registered Professional Engineer in the State of Texas.
Scott Barfield-McGinnis, P.E. Standards Developer North American Electric Reliability Corporation 3353 Peachtree Road, NE Suite 600 – North Tower Atlanta, Georgia 30326 scott.barfield@nerc.net	Mr. Barfield-McGinnis supports NERC's Reliability Standards Development group and NERC's continual mission of managing and improving standard development, revisions, interpretations, and other Reliability Standards related projects through the valued participation of industry technical subject matter experts. Before joining NERC, he was the Bulk Electric System Compliance Manager at Georgia System Operations Corporation. Other positions held throughout his 27-year career in power include system engineer, planner, and engineering manager with oversight in energy control systems, planning and forecasting, as well as, asset management. Mr. Barfield-McGinnis received a Bachelor of Science in Electrical Engineering Technology degree from the Southern Polytechnic State University in Marietta, Georgia in 1994 and a Master of Business Administration degree from Mercer University in Atlanta, Georgia in 2008, and a registered Professional Engineer in the State of Georgia. He is also a member of the Institute of Electrical and Electronics Engineers (IEEE), past Board Member of the IEEE Central Georgia Section, and continues to provide technical presentations at IEEE functions.
Philip J. Tatro, P.E. Senior Performance and Analysis Engineer North American Electric Reliability Corporation 3353 Peachtree Road NE Suite 600 – North Tower Atlanta, Georgia 30326 phil.tatro@nerc.net	Mr. Tatro is a Senior Performance and Analysis Engineer in NERC's Reliability Initiatives and System Analysis group and has 27 years of industry experience. He is the NERC staff coordinator for the System Protection Control Subcommittee and provides technical expertise to several standard development projects, event analyses, and reliability initiatives. Prior to joining NERC he worked for 23 years at New England Electric System and National Grid. His experience there included assignments in Protection and Control Engineering, the Québec-New England 2,000 MW HVdc interconnection, development of independent transmission projects, and Transmission Planning. During this time he was a member of several NERC, Northeast Power Coordinating Council (NPCC) and New England Power Pool committees, task forces, and standard drafting teams. Mr. Tatro chaired the NPCC SS-38 Working Group on Inter-Area Dynamic Analysis and the NERC Major System Disturbance Task Force responsible for dynamic simulation of the August 14, 2003 blackout. Mr. Tatro received Bachelor of Science and Master of Engineering degrees from Rensselaer Polytechnic Institute in Troy, New York in 1985 and 1986 respectively. He is a registered Professional Engineer in the Commonwealth of Massachusetts. He is a member of the Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society and is an active participant in the IEEE Power System Relaying Committee.